

directs FERC to issue and enforce regulations to ensure that a utility recovers all prudently-incurred costs associated with a QF purchase under the contract. This provision was intended to codify case law that has held that state commissions cannot disallow the pass through to a utility's ratepayers of QF payments made by the utility if they were made at or below the utility's avoided costs at the time the purchase obligation was established.

This issue is important not only to purchasing utilities, but also to QFs whose contracts contain so-called "regulatory-out" clauses.

Regulatory-out clauses permit the purchasing utility to reduce payments to QFs to the extent that the utility cannot pass through the QF payment to the utility's retail customers. Since issuance of the *Freehold Cogeneration* decision in 1995 by a US appeals court, which held that such pass through of payments was required by federal law, states have generally refrained from challenging the pass through of QF payments in retail rates, although a few have made statements that suggest that a future challenge may be in the offing. In the proposed rulemaking, FERC concluded that no regulations on this issue "were necessary at this time," but sought comments about the need for such a regulation. ☺

California: The Promised Land for Renewable Energy?

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A new mantra can be heard these days in California: renewable energy is good, and more renewable energy is better.

In California's post-crisis energy market, there is nearly unanimous consensus that renewable energy should play a greater role. In 2002, the legislature passed Senate Bill 1078, which set a goal of obtaining 20% of the state's electricity from renewable energy sources by 2017. Regulators pushed to advance the goal by seven years to 2010. More recently Governor Schwarzenegger challenged the state to raise the goal to 33% by 2020. Politicians and regulators now find themselves in an unlikely competition to / continued page 14

building — and not the part that is equipment. Usually no more than 5% of a large power plant is considered real property. The rest is treated as equipment.

The rulings involved two factories that a developer wanted to finance using lease financing.

The problem is the special depreciation can only be claimed on property that is used in a trade or business *of the taxpayer* on the reservation. In a lease, the lessor is the taxpayer. The standard triple net lease of a project — where the lessee treats the project essentially as its own during the lease term — does not put the lessor in an active trade or business on the reservation.

A special rule in section 168(j)(5) of the US tax code makes an exception for leases of real property. A lessor of real property is viewed as engaged in an active trade or business on the reservation.

The lessor argued that it should be able to look to Oklahoma law, where the factories are located, for direction on how much of each factory is real property. However, the IRS said that it would determine what is real property by looking instead at the rules for investment tax credits. These rules treat projects like factories and power plants largely as equipment. The rulings are Private Letter Rulings 200601019 and 200601020. The IRS made them public in January.

In related news, an Indian tribe is potentially in hot water for issuing tax-exempt bonds to finance a hotel and convention facility on a reservation.

Tribes have the power — like state and local governments — to issue tax-exempt bonds to finance public facilities. However, the power given tribes is more limited. The bonds must be used for an "essential governmental function." The IRS told the tribe on audit that it had questions about the tax exemption for the bonds the tribe issued. The issue went to the IRS national office in / continued page 15

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be the strongest advocate for renewable energy, while both buyers and sellers of renewable energy are challenged to respond to this opportunity.

With the legislature's passage of Senate Bill 1078, California enacted one of the most aggressive renewable portfolio standards in the nation. The statutory RPS mandate calls for certain types of electricity providers to meet 20% of their electricity load with eligible sources of renewable energy by 2017. Regulators and the state's three major investor-owned utilities have committed to meeting that goal by 2010.

California is embarking on a path that could deliver a robust market for providers of renewable energy technologies and numerous project and financial opportunities to the investment community.

Nevertheless, California's renewable energy goal — whether it be 20% or 33% — is a “stretch” goal for the utilities and the renewable industry. Before this promised land arrives, challenges must be met.

Progress over the past two to three years has been disappointing and is forcing some critical thinking about the regulatory framework being constructed to support California's grand vision for renewable energy. Although there have been

numerous workshops and regulatory proceedings to implement the RPS, relatively few contracts have been signed and approved. Many of those contracts are for projects that are turning out to be infeasible. Some form of mid-course correction is likely over the next couple of years. Achieving these goals will require a heady mixture of technology advances, economies of scale, high alternative fuel costs, and federal incentives. If achieved, the goals may prove to be a “tipping point” for renewable energy technologies and the industry.

Deep Roots and a Grand Future

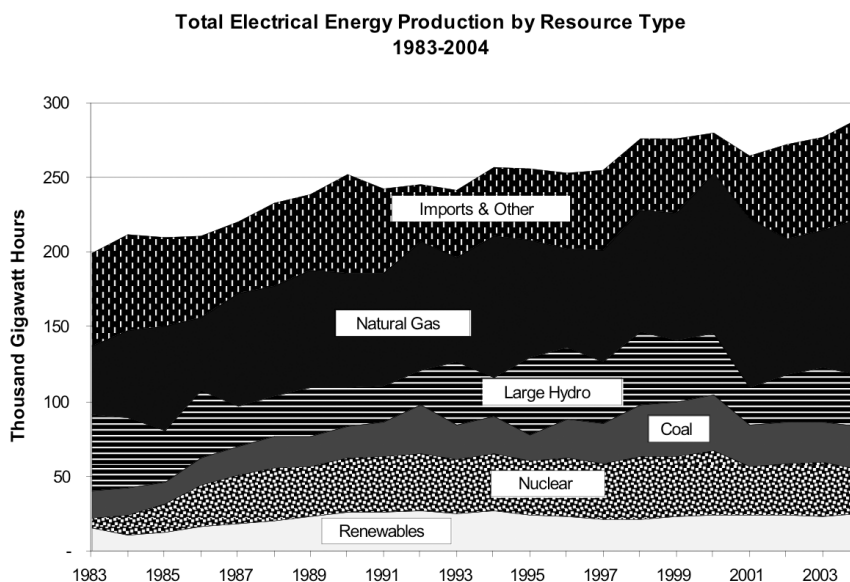
California has long been at the forefront of promoting renewable energy technologies. Hydroelectric generation and the combustion of forest products for electricity generation date back many decades. Pacific Gas and Electric and Magma/Unocal pioneered the use of geothermal steam to produce electricity at the Geysers more than 50 years ago. In the late 1970s Governor Edmund G. (“Jerry”) Brown promoted energy efficiency, cogeneration and solar, wind and biomass technologies as alternatives to building more nuclear and coal-fired power plants. By the mid-1980s generous tax credits and standardized power sales agreements with the state's investor-owned utilities had sparked a new phase of renewable energy development. Large-scale development of cogeneration and biomass combustion facilities, the commercialization of modern wind machines, the develop-

ment of geothermal facilities using the Imperial Valley's low-temperature and high-brine resource anomalies, and research into experimental facilities such as parabolic trough solar power plants and an integrated gasifier combined-cycle power plant all benefited from California's support of renewable energy development.

Renewable energy as a percentage of California's overall electricity supply mix reached nearly 13% in 1993. (See Figure 1).

Readily available, low-cost natural gas, high-efficiency combined-cycle power plants and surplus power in the western US power markets eroded the competitive position of renewable energy in the 1990s.

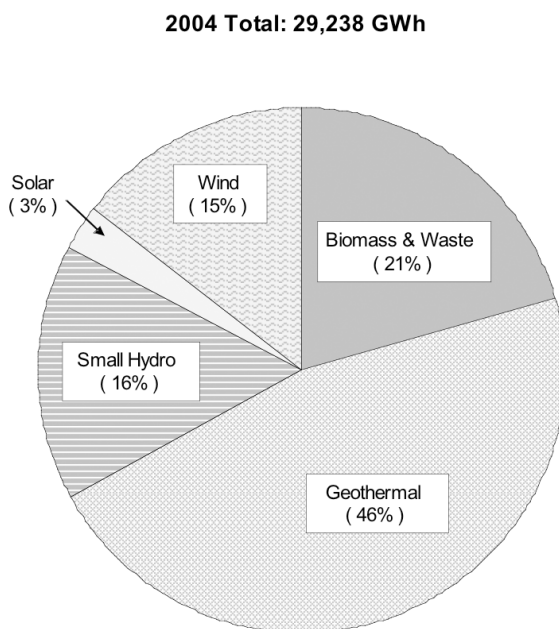
Figure 1



Moreover, the public policy debate shifted focus to a reliance on market signals to lead development of new electricity supplies. As a result of these factors, renewable energy development experienced a setback in the mid-1990s. Efforts to revive renewable energy development began again in 1998 when the California Energy Commission launched its renewable energy program with funding derived in part from a public goods surcharge assessed on ratepayers' utility bills. When the energy crisis rocked California in 2000-2001, renewable energy generation accounted for approximately 10% of total generation, a three-percentage point drop in one decade.

Soaring oil and gas prices, concern for climate change and lingering fears of adequate energy supply have led to renewed support for renewable energy. In 2004 California produced nearly 30,000 gigawatt-hours of renewable energy. Figure 2 provides a breakdown of California's renewable energy production in 2004 by resource type.

Figure 2



As one of California's responses to the energy crisis, legislators and regulators have taken steps to increase the number of renewable energy resources that supply electricity to California. One of the most significant steps was the adoption of the 20% renewable portfolio standard in September 2002. The law requires that 20% of the energy supplied by certain retail suppliers to

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Washington for resolution.

The national office confirmed in a "technical advice memorandum" — or ruling to settle a dispute between a taxpayer and an IRS agent in the field — that the tribe may only use tax-exempt bonds to finance essential governmental functions that are customarily performed by state and local governments. The ruling is Technical Advice Memorandum 200603028.

US POWER COMPANIES complain that proposed IRS regulations would deny them a special tax break for domestic manufacturing in cases where a power plant is owned by two or more companies through a partnership or limited liability company, and each company takes and sells its share of the electricity in kind.

The corporate income tax rate in the United States is 35%. However, income from domestic manufacturing is taxed at a lower rate. Generating electricity or producing natural gas or potable water is considered "manufacturing." Moving these items across power lines or through gas or water mains is not. Companies that do both must allocate their earnings.

A company can exclude 3% of its domestic manufacturing income from federal income taxes in 2006, 6% in 2007 through 2009, and 9% thereafter. This translates into a 34% tax rate in 2006, 33% rate in 2007 through 2009, and a 32% rate thereafter. Even a 1% rate reduction can be worth several million dollars in tax savings.

To qualify for a rate reduction, the company selling the output must have done the "manufacturing" itself. The IRS takes the position in proposed regulations that where a power plant is owned by a partnership, the partnership does the manufacturing. The individual partners do not. This is not a problem if the partnership sells the electricity and allocates income from

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their electricity customers must come from renewable resources by 2017. (See the sidebar for an overview of the California RPS.) As an interim measure until the RPS legislation could be implemented, regulators ordered the investor-owned utilities to solicit contracts in 2002 for electricity generated by renewable energy resources.

Not content with the proposed pace of renewable resource development implicit in the RPS, the California Energy Commission, the California Public Utilities Commission, and the now-defunct California Power Authority authored an energy action plan in 2003 that established a more aggressive RPS target date of 2010 by which renewable energy would supply 20% of electrical load. (An updated energy action plan was released in 2005). Governor Schwarzenegger endorsed the accelerated schedule and also called for a *statewide* goal that 33% of the energy supplied should come from renewable energy resources by 2020. California’s RPS target is among the most aggressive targets adopted by any of the other 21 states and the District of Columbia that have adopted RPS mandates. The IOUs have publicly expressed their intention to meet the more aggressive target established in the 2003 energy action plan.

In addition to promoting the development of utility-scale renewable energy through implementation of the RPS, the California Public Utilities Commission recently authorized approximately \$2.9 billion in funding for an initiative to install thousands of megawatts of roof-top photovoltaics throughout the state. This program is similar to the “million solar roofs” legislative initiative supported by Governor Schwarzenegger that stalled in the legislature. The goal of the CPUC’s program is to stimulate demand for photovoltaics through a subsidy with guaranteed funding for ten years. It replaces a smaller program administered by the California Energy Commission. The size of the new program and its regulatory stability is expected to support investment in

manufacturing that may lead to a reduction in costs. Similar programs have been successful in reducing photovoltaic costs in both Japan and Germany. As the market grows and costs decline, the amount of the subsidy is reduced.

The program is expected ultimately to result in up to 3,000 megawatts of new roof-top solar capacity.

Renewable Energy Targets

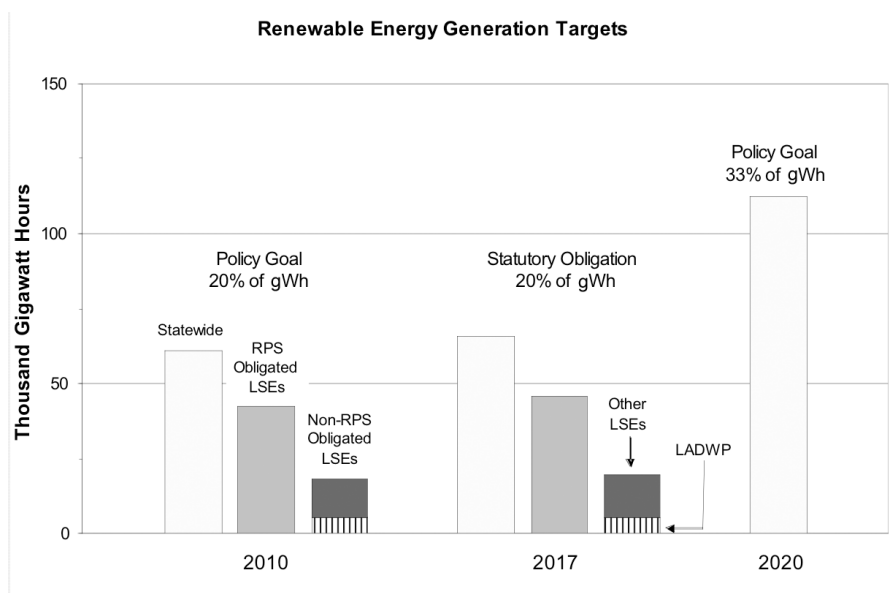
The California RPS legislation established renewable energy targets for three classes of retail sellers of electricity: the investor-owned utilities, energy service providers — called “ESPs” — and community choice aggregators — or “CCAs.”

Up until the end of 2005, only California’s three major utilities — PG&E, Southern California Edison and San Diego Gas & Electric — had to comply with the state-mandated RPS target. The CPUC recently extended the RPS policies to ESPs and CCAs.

Publicly-owned utilities such as the Los Angeles Department of Water and Power are not required under the law to meet a specific renewable energy target, but they are required to develop their own RPS policies. Many publicly-owned utilities, including Sacramento Municipal Utility District and Silicon Valley Power, have aggressive renewable energy procurement policies in place. LADWP, under the new leadership of Mayor Villaraigosa, has also committed to increase its purchases of renewable energy significantly.

California’s electric loads are currently split about 70:30

Figure 3



between the investor-owned utilities that are regulated by the CPUC and publicly-owned utilities. Each of the IOUs' customer bases includes bundled electric customers who procure their power from the IOUs, but also so-called direct access customers who buy their power from ESPs. In the near future, cities may begin to procure power for their residents and businesses, forming an entity known as a "community choice aggregator." (San Francisco and Chula Vista are two cities pursuing this option.) ESPs currently provide electricity for about 13% of the IOUs' loads; CCAs could serve another 5% by 2010.

Based on electricity demand projections made by the California Energy Commission, California's total electricity demand in 2017 is expected to be approximately 330,000 gigawatt-hours. If the 20% RPS target is achieved, renewable energy resources would be generating 66,000 gWh of electricity in 2017. Twenty percent of expected electricity demand in 2010 is 61,100 gWh, and 33% of expected electricity demand in 2020 is 112,700 gWh. Figure 3 provides a breakdown of how the different targets for renewable energy translate into the need for renewable generation. (It uses the acronym "LSE" for load-serving entities.)

How the amount of needed renewable *energy* translates into the amount of new renewable generation *capacity* depends on which resources are developed and other factors. The key variable is the blend of the new renewable generation portfolio, since different renewable generators produce very different amounts of energy per unit of installed capacity.

Assuming that the energy targets for new renewables are met by a portfolio consisting of 50% wind, 30% geothermal, 10% biomass and 10% solar, we estimate that the state will require approximately 8,600 megawatts of additional renewable generation between now and 2010.

This would consist of about 5,200 megawatts from wind, 1,200 megawatts from geothermal, 400 megawatts from biomass and 1,800 megawatts from solar.

According to a study prepared for the California Energy Commission, a majority of this additional supply, roughly 6,000 megawatts, can be provided by resources located in California that can be delivered with little change to the existing transmission system. In order to meet the RPS target using in-state renewable resources, California will require investment in transmission capacity to enable delivery from additional resources.

Of course, the amount of new renew- / *continued page 18*

the sale to the partners. The sales revenue is domestic manufacturing income to the partnership, and it retains that character when distributed to the partners. The problem is where electricity is distributed in kind and the partners sell their shares of the electricity individually. The sales revenue does not qualify in that case since the *partner* was not the manufacturer of the electricity.

The IRS proposed a special rule for partnerships engaged solely in the extraction, refining or processing of oil or natural gas. Partners in such partnerships can take their shares of the oil or gas in kind, sell it and still qualify for the rate reduction.

Electric utilities, mining companies and petrochemicals companies are urging the IRS to adopt a similar exception for their industries. Final regulations are expected in early May.

SYNFUEL AND LANDFILL GAS PRODUCERS are fretting about whether high oil prices will cause federal tax credits for their projects to phase out.

In the meantime, two synfuel plant owners received good news in their audits with the IRS.

The US government allows anyone producing synthetic fuel from coal or landfill gas to claim tax credits of \$1.13 an mBtu on the output. This is the credit amount for output during 2004. The synfuel plant or gas collection system must have been put into service by June 30, 1998 to qualify for credits. The credits run through 2007. However, they phase out if oil prices return to levels reached during the Arab oil embargo in the mid-1970's. Credits would have phased out during 2004 as oil prices moved across a range of \$51.35 to \$64.46 a barrel. Both the tax credit and the phaseout range are adjusted each year for inflation. The 2005 figures will be announced by the IRS around April 1. The relevant oil price is the average wellhead price for / *continued page 19*

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able generation capacity will also depend on a number of other factors, including load growth and the amount of existing renewable capacity that remains online after current contracts with the investor-owned utilities expire. Much of the IOUs' current eligible renewable generation comes from "qualifying facility" projects, so a significant loss of these plants would result in the need for a much more rapid development of new generation, especially between 2010 and 2020, which is when most of the contracts with renewable energy QF resources expire.

To go beyond the 20% in 2010 goal to the much more aggressive target of 33% by 2020 would require a redoubling of new resource development and will require investments in transmission to access additional resources. Figure 4 presents annual capacity additions for a potential renewable development plan using the same assumptions for the new renewable portfolio as used above.

As this figure shows, the state will require over 12,000 megawatts of incremental renewable capacity between 2010 and 2020 to achieve 33% renewable supply by 2020. California certainly has the technical potential to meet these

targets using native resources; the California wind potential is estimated at over 15,000 megawatts with another 15,000 megawatts available from solar resources. However, given transmission constraints and other factors that limit the availability of cost-effective in-state renewable resources, the state may need to consider allowing out-of-state resources to be used to meet the 33% goal. It is important to keep in mind that the 33% target is only a policy goal at the present time and has not been fully defined. Shifting political winds, changes in fuel prices and the cost recovery associated with the state's renewable program will all play an important role in whether the current policy goal persists over time.

Early Results

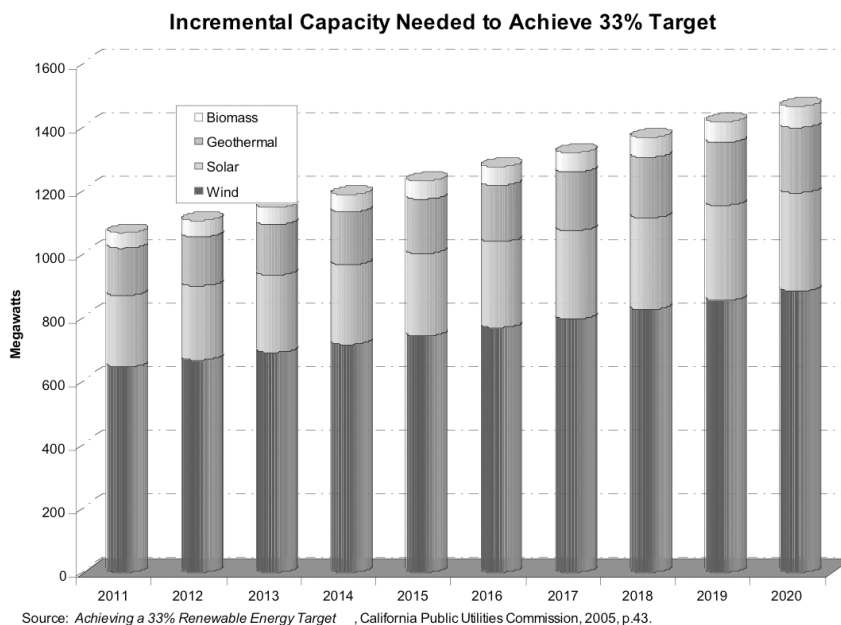
Implementation of the California RPS legislation has not proceeded smoothly, and initial timelines have been extended repeatedly to account for delays.

Regulatory proceedings to establish implementation policies have been fragmented and contentious. The CPUC has issued at least eight separate decisions over a three-year period that rule on key structural issues for implementing the RPS. Some elements of the RPS legislation are only now being considered, three years after the passage of the legislation. Moreover, unlike RPS statutes in other states, California's

RPS legislation delegated regulatory oversight to two state agencies, the California Energy Commission and the CPUC. Utilities, project developers and other stakeholders must navigate a multi-year, dual-agency regulatory process in order to understand and comply with the California RPS.

Although the regulatory process has not been straightforward, the investor-owned utilities have completed several rounds of competitive solicitations for renewable energy since 2002. They have also negotiated bilateral contracts outside the solicitation framework. As a result of these efforts, the combined purchases of renewable energy for PG&E, Southern California Edison and SDG&E have increased from over 19,000 gWh in 2002 to just over 23,000 gWh in 2005.

Figure 4



Purchases of renewable energy in 2004 accounted for 13.9% of the three utilities' combined load.

These initial results, while promising, may not be sufficient to keep the utilities on track to meet the 20% goal by 2010. In fact, PG&E under-procured renewable energy by 884 gWh relative to its procurement target in 2004 and by 1,177 gWh in 2005. Southern California Edison has also fallen short, missing its 2005 target by 274 gWh.

In addition, much of the purchases of renewable energy during the first three years of the RPS program came from existing renewable energy generation capacity. Thus, the early stages of the California RPS have not led to development of new renewable generation capacity, but rather have resulted in the diversion of sales from other buyers to the IOUs. As the annual incremental targets increase and other load-serving entities are brought in under the RPS umbrella, there will be greater dependence on new projects.

The bidding and contracting process has proven to be cumbersome as well. Early experience from the IOUs' renewable energy solicitations shows that it takes about two years between the time that a solicitation is held until construction on a project begins. A large portion of the delay can be attributed to utility administration of the procurement process rather than regulatory delay. For example, PG&E held a round of solicitations in July 2004 but only completed negotiations with bidders in April 2005. Southern California Edison did not complete negotiations with bidders following an August 2003 solicitation until 2005.

The California RPS legislation requires the use of a "least-cost, best-fit" criteria in the procurement of renewable energy resources. The CPUC defined "best fit" as the resources best able to meet the utility's energy, capacity, ancillary service and local reliability needs. Because the least-cost, best-fit criteria is unique to each utility, the utilities have developed their own methodologies for how the criteria should be applied. However, the utilities provide only general, qualitative descriptions of their methodologies, creating a lack of transparency in the application of the criteria that has become quite controversial.

Contract failure is emerging as a potential major stumbling block to the achievement of California's renewable energy goals. Southern California Edison recently reported to the CPUC that at least six of eight projects that received contracts following its 2003 solicitation, and that were expected to be operational in 2006, / *continued page 20*

domestic crude oil for the entire year, which has historically been 85% to 89% of the price for oil contracts traded on NYMEX.

The IRS has disallowed tax credits at a number of synfuel plants on various grounds. Some of the audits are still moving through appeals. In two of the audits where the sole issue was whether the plants were put into service in time, the IRS field teams handling the audits agreed to submit the issue to the IRS national office for a ruling. The national office ruled for the taxpayer in one of the audits — involving three synfuel plants — last June. The IRS has now also ruled for the taxpayer in the second of the two audits, according to the taxpayer involved, Progress Energy. The result is good news for synfuel plant owners. The first case decided last June involved synfuel plants that had some of the strongest facts of any synfuel plants. The latest batch of four plants that were the focus of the second audit had weaker facts.

Duquesne Power & Light said within days after the Progress announcement that the IRS field team had decided to give up on its audit, apparently after learning of the result in the Progress audit.

Other cases are still pending, but are working their way through appeals rather than the IRS national office. The IRS field teams handling those audits have refused to let the cases be heard in Washington. In some of the audits, IRS agents have raised additional grounds beyond whether the plants were put into service in time.

Meanwhile, synfuel and landfill gas producers are waiting to see whether a tax reconciliation bill that is in the final stages of moving through Congress will include language the Senate added to the bill last November that would change how the oil price phaseout works. The current phaseout is linked to oil prices during the current year. The Senate voted to link it to oil prices the year before. Thus, whether credits / *continued page 21*

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may not achieve commercial operation until 2010. Additionally, a 5 megawatt solar project and a large biomass plant signed bilateral contracts with Southern California Edison, but then failed to gain regulatory approval. Given the likelihood of additional contract failures, it has been recommended that California regulators require that utilities contract for supplies in excess of their projected needs

California has set a goal of generating at least 20% of its electricity from renewables by 2017, but the utilities are trying to reach this goal within the next four years.

to ensure that the energy targets are met according to schedule and contract failure is not used as an excuse for failure to comply.

Transmission Expansion and Policies

Even if sufficient contracts for renewable energy are signed, delivering the energy and capacity from those contracted projects poses significant challenges.

Among the most critical challenges to overcome are transmission planning and permitting policies, transmission system expansion and transmission cost recovery policies. Achieving California's renewable energy goals will require resolution of a variety of transmission bottlenecks in 2006.

The regulatory responsibility for transmission planning, permitting and ratemaking is spread across federal and state agencies and at the state level among a number of state energy agencies. In California, three state agencies have various responsibilities for transmission planning and permitting. The California Energy Commission conducts

resource planning studies that identify the potential need for and size of transmission upgrades. Under its Federal Energy Regulatory Commission-approved tariffs, the California ISO has jurisdiction to approve any needed transmission projects. The CPUC has jurisdiction over the siting of transmission lines and must issue a certificate of public convenience and necessity for any California ISO-approved project that is not exempted from siting requirements. Finally, FERC must approve the inclusion of a transmission project's costs in transmission rates. Concerns about under-investment in

California's transmission infrastructure have led to consideration of jurisdictional reform and public disagreements between the California Energy Commission and the CPUC about the need for such reforms.

In December 2005, Southern California Edison reported to the CPUC that although its baseline renewable energy position in 2003 was about 18%, it was unlikely to meet the 20% by 2010 goal because licensing and

constructing new transmission facilities necessary to interconnect new renewable generation projects likely would not be completed in a timely manner. According to Edison, many generation projects are located in the California ISO interconnection queue ahead of eight renewable energy projects with which Edison has signed contracts.

The typical length of time from when a generator applies to the California ISO for interconnection to the completion of the transmission upgrade ranges from approximately five to seven years.

In late January, the investor-owned utilities filed supplemental material with the CPUC concerning the implications of transmission issues for successful implementation of their renewable plans.

Southern California Edison's quandary may have shocked California policymakers, but they should not be surprised about the pivotal role that transmission infrastructure will play in achieving the state's renewable goals. For example, SDG&E has frequently said in filings before regulatory

authorities that significant new transmission capacity in its service area is needed to achieve the 20% renewable goal. All three IOUs may need to expand transmission capacity into areas with substantial renewable resources.

A significant amount of California's renewable energy potential exists in areas far from the transmission system. In order for the state to achieve its aggressive renewable energy goals, at least some portion of this geographically remote potential must be tapped. However, expanding the state's transmission system within the proposed RPS timeframe is a formidable challenge.

A number of transmission projects that would tap into California's diverse mix of renewable resources have been proposed, including the following:

Tehachapi Transmission Plan: An area of California known as Tehachapi contains the largest wind resources in the state. Existing wind facilities have a total capacity of about 645 megawatts. The California Energy Commission estimates that the area's undeveloped wind potential totals 4,500 megawatts (peak capacity) or 14,000 gWh per year. A group known as the Tehachapi Collaborative Study Group that includes representatives of PG&E, Edison, developers and regulators has been attempting to develop and to implement a consensus transmission plan for the Tehachapi resources. The CPUC concluded that a traditional "application-based" approach to siting transmission lines for individual projects in the Tehachapi area would not be cost-effective nor would it likely yield the level of infrastructure needed to take full advantage of Tehachapi's wind resources. The CPUC encouraged Southern California Edison to apply to FERC for innovative rate treatment of a comprehensive approach to transmission needs for this area, but Edison received only partial approval from FERC. Consequently, Edison has applied for CPUC approval only for a first phase project known as the Antelope transmission project.

Imperial Valley Transmission Upgrade: California's Imperial Valley contains sizable geothermal and solar resources. Existing geothermal generation capacity totals about 450 megawatts. Developers estimate there is potential to develop an additional 1,350 to 1,950 megawatts over the next 15 years. Large-scale solar thermal electric projects have also been proposed in the Imperial Valley. A group known as the Imperial Valley Study Group, comprising the Imperial Irrigation District, LADWP, SDG&E, developers and regulators is studying options for developing trans-

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phase out during 2006 would be linked to oil prices during 2005. The Senate "paid" for the provision by dropping the inflation adjustment for the credit itself. Thus, the credit amount would remain fixed at the 2004 level of \$1.13 an mmBtu. However, the oil price phaseout range would continue to be adjusted for inflation.

The industry benefited from a good lobbying strategy and fortunate timing. The Joint Tax Committee staff, which scores tax proposals for their revenue effects, said last November that the Senate provision would raise money for the government. The forecast of oil prices that it was using at the time suggested prices would not reach the phase-out range during 2006 or 2007. Therefore, it concluded that the government would collect an extra \$151 million in revenue over five years as a consequence of freezing tax credits at the 2004 amount.

The debate has now shifted to a House-Senate conference committee. The House did not have a similar oil price provision in its version of the tax reconciliation bill. House negotiators are expected to resist including the provision in the final bill. A hostile news article in *Time* magazine in late February appears to have been planted by opponents of the Senate provision either at Treasury or in the House. Two coalitions of synfuel plant owners are lobbying hard to keep it.

In another development, the owners of five synfuel plants failed in an effort to have a federal district court in Pennsylvania declare that their plants were put in service in time to qualify for tax credits.

The IRS does not usually rule outside of a tax audit about when plants were put into service because it considers the issue too factual. A prior owner of the five plants went into bankruptcy. The bankruptcy court involved at the time recited in the fact portion of an opinion on unrelated bankruptcy issues that the plants qualify for tax credits. The current owners of the plants tried

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An Overview of California's Renewable Portfolio Standard

Senate Bill 1078, approved in September 2002, established a renewable portfolio standard. The RPS legislation requires all retail energy providers, including electrical corporations, community choice aggregators and electric service providers, to increase their procurement of renewable energy by at least 1% each year so that 20% of their total energy is procured from renewable sources by 2017. In 2003, the California Public Utilities Commission adopted regulations implementing the RPS for investor-owned utilities under its jurisdiction.

CPUC regulations require the utilities to administer annual RPS solicitations according to CPUC prescribed rules. Winning bids are selected by the utilities using "least-cost, best-fit" criteria, and contracts must be approved by the CPUC. The evaluation of bids must include estimated transmission costs based on a transmission ranking cost report issued by the CPUC. The selected bids are compared to a CPUC-calculated market price referent, or "MPR," that estimates a long-term market price for electricity from conventional sources. Contracts at or below the MPR are automatically determined to be reasonable. Any approved bids requiring payments above the MPR will be considered by the California Energy Commission for supplemental energy payments using funds collected through the public goods charge. To date, all winning contracts have been priced below the MPR. In 2005 the 20% RPS requirement was extended to all load-serving entities under the CPUC's jurisdiction, including direct access providers and community choice aggregators.

The California RPS legislation established which renewable / [continued page 23](#)

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mission capacity that could deliver up to 2,200 megawatts of geothermal and solar generation output to electricity customers. Plans to expand transmission access in this region have proceeded along two independent but closely linked paths.

One is the "green path project." In November 2005, Los Angeles Mayor Villaraigosa announced that the city had entered into a partnership with the Imperial Irrigation District and the non-profit organization Citizens Energy to build the "green path" project. The project seeks to upgrade existing transmission lines and create new interconnection points that will enable LADWP to tap into the Imperial Valley's renewable resources at the Salton Sea. The green path project would make a substantial contribution to the mayor's goal of LADWP supplying 20% of its power from renewable energy in 2010.

The other option is the "Sunrise power link." SDG&E recently proposed a new 500 kV transmission line, known as the Sunrise power link, to connect its service territory to the Imperial Valley. SDG&E has not determined the specific location the transmission line would travel, and the earliest projected in-service date is 2010. SDG&E contends this new transmission line is necessary in order for the utility to access much of the renewable resources that it has under contract and also to meet its RPS obligations of 20% in 2010. SDG&E has advocated use of renewable energy credits as another way for it to meet its RPS obligations, but this proposal is controversial.

Out-of-State Renewable Resources: PG&E has advocated that California evaluate its need for transmission infrastructure based upon resource availability throughout the west. Governor Schwarzenegger has led efforts by the Western Governors' Association to plan and develop energy resources on a regional basis. PG&E is concerned that California's efforts to find transmission solutions to access its remote renewable resources in the Tehachapi area and Imperial Valley may lead to suboptimal transmission investments relative to a plan that considers transmission solutions across the western United States. The Northwest Transmission Assessment Committee has identified large amounts of renewable resources outside California. Thus, PG&E's ratepayers may find enhanced transmission capabil-

ity to the Pacific Northwest more attractive than upgrades south to the Tehachapi area. In November 2005, PG&E announced a partnership with Sea Breeze Pacific West Coast Cable to study a 650-mile undersea high-voltage direct current cable that would connect the San Francisco area with the Portland area in Oregon.

The final issue that must be addressed in order to ensure needed transmission investments are made is cost recovery. Historically, federal and state policies concerning cost responsibility for transmission upgrades have laid the burden on the developer whose project causes the need for an upgrade. This first developer ends up footing the bill for a transmission upgrade that subsequent developers can utilize for their projects. This cost responsibility policy traditionally was not a problem because developers of large-scale fossil-fueled projects generally had the financial resources to absorb the costs. Developers of smaller-scale renewable energy generation projects may not have the financial wherewithal to fund a needed transmission system upgrade to accomplish project interconnection. Moreover, a series of incremental interconnection projects may have a relatively high cost relative to a comprehensive approach.

In March 2005, Southern California Edison proposed a new type of transmission line that it called a “renewable-resource trunk line.”

As proposed, the trunk line would have interconnected about 1,100 megawatts of mostly wind plants located in areas remote from major load centers. Costs of constructing the trunk line were to be recovered through general transmission rates. Although the trunk line was proposed by Edison, the line would have been operated by the state’s transmission system operator, and utilities other than Edison would be able to use the trunk line to tap renewable resources to meet their RPS goals. California’s regulators supported the proposal, but FERC did not approve the trunk line. Instead FERC provided Southern California Edison with advance cost recovery assurances for the Antelope transmission projects portion of the more comprehensive transmission plan for the Tehachapi. According to California regulators, FERC’s rejection of the proposed trunk line removes “the primary instrument the state could have used to address transmission constraints for renewables.”

The experience with Edison’s / *continued page 24*

An Overview of California’s Renewable Portfolio Standard

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resources are eligible to be counted toward the RPS targets. Qualifying technologies are biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuel, hydroelectric generation with capacities less than 30 megawatts, digester gas, municipal solid waste conversion using a non-combustion thermal process, landfill gas, ocean wave, ocean thermal and tidal current. An eligible renewable resource must also be located in California or near the state border so that the first point of interconnection to the transmission system is within California. Existing resources under the control of the investor-owned utilities count toward the baseline for each utility. The amount of renewables that must be purchased each year is equal to the baseline from the previous year plus 1% of the utilities’ retail sales for the previous year. Utilities may bank renewables purchases to count towards future periods, and may carry forward shortfalls of up to 25% of their annual target for up to three years. Any shortfalls not fulfilled within the three-year make-up period will incur a penalty of 5¢ per kWh. ☉

A Financial Boost to California's Renewable Energy Goals

In 2004, the California Public Employees Retirement System — called “CalPERS” — approved plans to invest as much as \$200 million in “clean” technologies, including renewable energy technologies, through private equity, project finance and venture capital investments. (CalPERS also gave approval to invest \$500 million in public stocks of companies that produce environmentally-friendly products and technologies or demonstrate a commitment to protecting the environment.) CalPERS made its first investment in May 2005 when it committed \$15 million to NGEN Partners, LLC, a venture capital firm that makes early-stage investments in energy and environmental technologies. The Carlyle Group and Riverstone Holdings received funds from CalPERS for a \$300 million investment fund targeting renewable energy power projects. ©

California Renewables

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proposed renewable resource trunk line illustrates not only the challenge that cost recovery policies pose to transmission system development, but also how competing jurisdiction over transmission planning, policies and rates acts as a roadblock to achieving California's RPS goals.

Other Implementation Issues

There are many issues that threaten to slow if not derail California's progress toward its RPS target.

Renewable energy credits are in use elsewhere in the US, but their role in California continues to be hotly debated. Uncertainty over future extensions to federal tax incentives will continue to plague project development. Land use and other environmental quality issues may emerge during the permitting process as the number of projects seeking permits escalates. Supplies of renewable energy equipment could tighten as other states and countries step up their own efforts to develop renewable energy projects.

California does not permit unbundled, or tradable, renewable energy credits to be used by a retail seller of electricity to meet an RPS target. (A renewable energy credit, or “REC,” represents the environmental attributes of the electricity produced. An unbundled REC separates these environmental attributes from the underlying electricity, allowing the environmental attributes to be sold, or traded, separately from the electricity.) The ability to use tradable RECs to meet an RPS target could ease the pressure for transmission investments and would make meeting RPS targets easier for ESPs and CCAs. But RECs have limitations as well. Because RECs are generally traded in short-term markets, they may not provide the type of long-term financial surety that renewable energy generators historically have needed. SDG&E has sponsored controversial legislation to allow RECs to be used to comply with the RPS requirements as part of a package to move the statutory RPS date from 2017 to 2010. Governor Schwarzenegger wants to broaden the eligibility for out-of-state renewables, while consumer advocates have been concerned that REC trading would expose California ratepayers to future market abuses by REC traders akin to the electricity crisis market manipulation allegations.

An obstacle to using tradable RECs to satisfy California's RPS targets is the current lack of a REC verification and tracking system. California's energy agencies are collaborating with other states in the West to establish the Western Renewable Energy Generation Information System (WREGIS). The system, which is expected to be operational in 2007, would serve as an independent data clearinghouse to facilitate verification, tracking and trading of RECs.

Even if a tracking system such as WREGIS was in place, there is debate within California as to whether the RPS legislation permits trading of unbundled RECs. New legislation may be required to provide the clear statutory foundation for using unbundled RECs to meet the RPS goals.

Production and investment tax credits provide critical financial support for renewable energy technologies. In 2005, Congress approved an extension of the 1.9 cent-per-kilowatt-hour tax credit for electricity generated with wind turbines over the first ten years of a project's operations. Without these financial incentives, the cost-effectiveness of some renewable energy projects would suffer. Congress periodically reviews these incentives and has approved extensions, but not without bruising political battles first taking place. These incentives have very specific eligibility requirements, so it will be crucial for developers to have competent tax attorneys.

A provision in the federal tax code concerning eligibility to receive the federal production tax incentive has become a major stumbling block to repowering. A repowered wind facility with a pre-1987 standard offer contract cannot receive federal tax incentives without a contract amendment. Current short-term avoided costs are much lower than many existing contract prices. Thus, wind facilities have little incentive to repower. According to the California Energy Commission, up to 1,000 megawatts of wind facilities in the state are candidates for repowering.

Most of California's new renewable projects will be located in relatively remote locations, which may simplify land use and permitting issues compared to more urban environments. However, renewable developments in these remote locations may well have significant adverse environmental impacts, so that land use planning and environmental mitigation issues are likely to become more widespread as renewable development expands.

A related issue is the high level of bird mortality associated with the operation of wind facilities. / continued page 26

to force the IRS to acknowledge in new court proceedings that the plants were in service in time by forcing the agency to acknowledge that the owners of the plants during 1998 were entitled to depreciate them that year. This would have established that the plants were in service.

The IRS refused to be drawn into the case, and the federal district court declined to issue an order finding that the IRS was bound by its failure to challenge the earlier depreciation deductions. The case is Dycoal v. Internal Revenue Service. The court released its decision on February 15.

OUT-OF-STATE LENDERS financing equipment in North Carolina must pay an annual tax on the face value of the loan, an appeals court said.

North Carolina taxes anyone engaged in the "business of dealing in, buying, or discounting installment paper, notes, bonds, contracts, or evidences of debt" that are secured by liens on equipment located in North Carolina. The tax is .277% of the face value of the debt. It is collected annually.

Navistar, a truck manufacturer, has a finance subsidiary that lends dealers and customers the money they need to purchase Navistar trucks. The finance subsidiary is based outside North Carolina. It has no office in the state. It brought suit in an effort to get back \$700,000 in taxes paid on installment paper over roughly a two-year period, arguing that it has too little "nexus" — or connection — with the state for the state to be able to tax it.

A state appeals court disagreed in a decision released in late February. The US constitution bars states from taxing persons who have little connection to the state or in a manner that discriminates against out-of-state residents or specially burdens interstate commerce. The court said the fact that the company holds liens over equipment in North Carolina gives it a substan- / continued page 27

Research suggests that bird deaths would be reduced if older, smaller wind turbines were replaced with fewer, larger wind turbines. Local officials in the Altamont area in northern California are particularly concerned with this issue and have limited the number of permits they will issue for new and repowered wind facilities.

The markets for renewable energy technologies are global and thus will be subject to the pressures of supply and demand in markets throughout the world. High oil prices have motivated many countries to push the development of renewable energy projects, resulting in a shortage of and increasing prices for certain equipment such as wind turbines. Promotional programs in certain markets may pull critical supplies from other markets. For example, the photovoltaics market has been strong in Japan and Germany in recent years as a result of government support for this technology.

Conclusions

Implementation of the California RPS legislation has not proceeded smoothly, and initial timelines have been extended repeatedly to account for delays. Regulatory proceedings to establish implementation policies have been fragmented and contentious. The IOUs have increased purchases of renewable energy, but their solicitations have not yet generated substantial new project development activity.

In short, the initial exuberance that led policymakers to propose the “20% by 2010” target has given way to growing concerns that procurement of renewable resources is taking too long.

Patience may be the key. California has significant, untapped renewable energy resources, so while the 20% by 2010 or 33% by 2020 goals are big, they are not unachievable. Planning for the necessary transmission upgrades is ongoing, so although the timing may not be optimal, transmission lines should eventually get built. The RPS framework needs fine-tuning, but it provides a regulatory push to develop renewable energy projects. As buyers and sellers gain experience with the RPS procurement process, they should be able to anticipate problems better and develop workable solutions. Finally, when a broad view is taken of the long-term social and environmental benefits of a greater reliance on renewable energy, California needs the RPS program to succeed. ☺

Mexico Encourages Renewables

by Mario E. Juarez and Hernando Becerra, with Ritch Muller, S.C.
in Mexico City

Mexico has taken the first step toward providing incentives to use renewable energy.

The Mexican House of Representatives (*Cámara de Diputados*) passed a “Law for the Use of Renewable Energy Sources” (*Ley para el Aprovechamiento de Fuentes Renovables de Energía*) in December, and the measure has now been sent to the Mexican Senate for its review and approval. Many believe that the law will be enacted this year.

Mexico has effectively committed, by ratifying the Kyoto protocol, to use more renewable energy as a source of electricity.

The installed generating capacity worldwide from renewables is 50,000 megawatts. Mexican installed capacity from renewables is just two and three megawatts. This leaves enormous room for growth. The Mexican Ministry of Energy estimates that there is potential to generate approximately 5,000 megawatts from wind power, 1,000 megawatts from biomass and 150 megawatts from biogas drawn from landfills.

The measure the House passed in December would favor seven kinds of renewables: wind, sunlight, water, the ocean, and biomass, biofuels or organic wastes.

The measure authorizes incentives to promote the use of such renewables, but it is vague and ambiguous about the type of incentives. This will be left largely to the Ministry of Energy — called SENER — to decide. The measure directs SENER to work with state and municipal governments. SENER is also supposed to coordinate with the Ministry of Economy on a package of incentives to encourage manufacturing of renewable energy equipment in Mexico.

Some of the incentives will be given only to Mexican utilities, like the *Comisión Federal de Electricidad* and *Luz y Fuerza del Centro*, and to Mexican-domiciled electricity generators (defined as Mexican individuals or entities organized under Mexican law and domiciled in Mexico).

It is not only the incentives that have been left vague, but the other details of the program to encourage renewables also remain to be worked out. The measure directs SENER to

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production. In order to ensure that the 2006 program was implemented in a timely fashion, the act established an initial default percentage of 2.78% to be used by EPA initially. The agency said that it intends in future years to adopt individual renewable fuels caps when it develops the necessary credit trading program for renewable fuels.

The 2.78% renewables standard should be easily met in 2006 by the petroleum fuels industry as a whole, primarily through the use of ethanol. Anticipated US gasoline sales of about 141.6 billion gallons will account for almost four billion gallons of ethanol — up from the 3.574 billion gallons of ethanol consumed in 2004, according to the Renewable Fuels Association. Biodiesel, on the other hand, cannot be blended with gasoline, but can be blended with diesel.

In future years, refiners and blenders that use more than the required percentages of renewable fuels in their products will receive credits that can be used in other refining or blending operations or by other refiners and blenders. Because the trading program has not yet been developed by EPA, no such credits will be generated in 2006.

New Source Review Case

A Federal district court dismissed a suit against the Tennessee Valley Authority in mid-January for alleged violations of the Clean Air Act at its Colbert plant in Alabama.

The case was brought by the National Parks Conservation Association in 2001, alleging that TVA

violated Clean Air Act new source review requirements by making modifications to its Colbert plant that increased emissions without obtaining a new or modified air permit, which permit would have required the installation of advanced pollution control equipment. TVA took the position that the modifications qualified as “routine repair and maintenance” that are exempted from new source review under EPA regulations. In a 2005 ruling, the court interpreted “routine maintenance” in a light favorable to TVA. The court decided that the term refers to projects that are routine within the industry, even if they are carried out once at each individual plant. In November, the court also granted TVA’s motion to dismiss the new source review claims, holding that the modifications had occurred more than five years before the lawsuit commenced and that, therefore, the claims were barred by the five-year statute of limitations period. The court ruled against the citizens’ group’s argument that the violations were continuous or ongoing because the resulting pollution continued to be emitted.

The decision to dismiss the case may now be appealed by the citizens’ group.

— *contributed by Andrew A. Giaccia, in Washington*

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