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Impact of Assembly Bill 32 Scoping Plan Resource Goals on New Natural Gas-fired Generation
Energy Commission staff, June 29, 2009

Question 1. What is the principle purpose and research questions of the study?
The purpose is to assess what would be the impact on natural gas-fired generation of different renewable resource mixes in light of complementary policies of energy efficiency, combined heat-and-power and CSI and of the State Water Resources Control Board's policy of reducing use of once-through cooling. By examining the natural gas aspects of integrating renewables, energy efficiency and CHP, staff investigated the timing, type, location and some of the services provided by existing and new natural gas-fired units.

Research Questions:
a) What is the consequence of adding Scoping Plan resources and a OTC compliance path on the incremental amount of renewables and on remaining system need for energy, capacity and type of ancillary services?
b) Is there a substantial difference between a high wind scenario and a high solar scenario on the location and performance of natural gas units used to firm up intermittent resources?
c) Would improving the granularity and internal consistency of load and wind resource characterizations reduce modeling uncertainty?
d) Could an intermediate treatment of local transmission constraints, inertia and local capacity requirements yield useful information on the location and performance factors of gas units?

Question 2. Brief description of methodology and links to documentation

This study method differs from other renewable integration investigations in that it incorporates complementary programs leading to lower total demand and a lower amount of incremental renewables needed to achieve a goal of 33 percent of 2020 retail sales. When those policies are assumed, the incremental renewables that are "net short" is 45,000 GWh compared to 74,000 to 75,000 GW in other studies. It also examines the impacts of OTC policy by replacing 7,758 MWs of existing, coastal gas-fired units with1,000 MW of combustion turbines and 6,758 MW of combined cycles.

The study uses a production cost model, Market Analytics, and data derived in California and WECC technical proceedings to assess trends in natural gas use for power generation under alternative resource development scenarios. It focuses on how intermittent resources might impact the need for new natural gas units if other policies in the ARB climate change Scoping Plan and the state's emerging policy regarding once-through cooling units meet policy targets. It does not assess the feasibility or cost-effectiveness of these complementary policies.

Staff developed three cases; one provides a reference case and the other two are "bookend" estimates. The Reference case does not include the Scoping Plan policies, only the assumption that the 20 percent renewable portfolio standard is met by 2012, statewide. The two bookend cases include statewide achievement of the Scoping Plan targets. The study implements a compliance path for the State Water Resources Control Board's pending policy to reduce the adverse impacts of once-through cooling from coastal gas-fired power plants. Gas-fired generation was added in CA control areas in order to maintain a 15 percent planning reserve margin. For areas outside of California, fossil fueled generation was added to meet a 15 percent planning reserve margin. The two bookend cases differed by the quantity of wind or central station solar added to meet a 33 percent renewable portfolio standard by 2020 (High Solar and High Wind).

Staff performed an assessment of available wind generation profiles. This assessment and the features of the production cost model lead staff to select the NREL Mesoscale wind shapes as the basis from which to create generalized wind profiles for regions in the West. In order to preserve characteristic wind variability, staff employed a technique to arrive at composite hourly wind shapes based upon the three historical years of hourly simulated wind generation developed by NREL.

The core of this technique is also used by staff in its development of load shapes. One difference in the development of the Energy Commission load shapes and wind shapes exists. Staff used five years of actual load data, 2002 through 2007, in the development of the load shapes, while the wind shapes were developed from the NREL data, which cover 2004 through 2006. Staff verified that the resulting shapes reflected prevailing historical relationships between wind generation and summer peak loads.

Staff's production cost model utilizes 33 separate composite profiles, based upon the NREL Mesoscale wind shapes, which are geographically assigned, matching the model topology to the NREL aggregate wind regions, throughout the western system. Each composite wind profile serves to approximate expected energy production in each hour from wind generation resources located in the associated region.

Link to documentation: http://www.energy.ca.gov/2009_energypolicy/notices/2009-06-29_workshop.html

Question 3. Key Drivers

Key Driver - Signal	Working Assumption / Approach
Retail Sales Forecast (2020)	CEC Final IEPR 07 demand forecast updated per LTTP decisions. Includes some embedded energy efficiency, solar PV, and CHP/DG excludes CDWR,WAPA MWD sales 308,070 GWh.
Incremental Energy Efficiency – CA	Case 1 contains only EE embedded in updated IEPR07 demand forecast. Case 2 and Case 3 include goals in the Scoping Plan (34,707 GWh* and 6,400 MW, at the time of system peak, in 2020).
Incremental CHP	Case 1 contains only DG Self-Gen embedded in updated IEPR07 demand forecast. Case 2 and Case 3 include Scoping Plan goal of 32,304 GWh* (4,700 MW). CHP is fueled by natural gas, baseload and its export power is must-take.
OTC generation retirements/replacements	Out of 15,069 MW existing gas-fired OTC, 12,655 MW retired 7,758 MW repowered/replaced by 2020 (1,000 MW simple cycle and 6,758 MW combined cycle).
Consistent Hourly Wind and Load Profiles	Composite hourly wind generation shapes and load profiles developed with the CEC shaping algorithm and verified against prevailing historical relationships (i.e. wind generation does not contribute significantly to meeting summer peak loads).
Long-Line Transmission from California to distant renewable resources (e.g. WY, BC, MT, NM)	New lines between BC and Northern California and Baja and Southern California in Case 2 High Wind.

*Includes transmission losses

Question 4. Findings and Conclusions

Renewable Net short findings

Adding the energy efficiency target level savings of 32,000 GWh (or 34,707 GWh when scaled up for transmission losses) reduced energy use across most hours, but also flattened the peak hour's load by up to 9 percent in 2020. There is a separate interagency effort underway to determine whether there is a set of program designs, which can deliver such high levels of incremental savings.

Adding rooftop solar up to AB 32 levels of 4,845 GWh did not have a large impact.

Adding the CHP reduced total retail sales and had a major impact on the electricity system dispatch, because the CHP export power is baseload and must-take. Since the CHP was fired by natural gas, it raised natural gas use. Sixty percent of CHP was located in southern California.

Including many demand-reducing policies, and hence reducing the amount of incremental renewables required to reach 33 percent of retail sales, the study required only 45,000 GWh of incremental renewables to be added compared to 74,000 – 75,000 GWh added in studies that do not include the entirety of the Scoping Plan's measures.

Three -fifths of the electricity savings impacts from achieving Scoping Plan resource goals came from energy efficiency, rooftop solar and combined heat and power, while two-fifths of the savings came from renewables.

Natural gas findings

The once-through cooling (OTC) policies had an impact on the proxy generation needed to firm up intermittent renewables. Much of the OTC generation, which needs to be retrofitted or replaced, serves local reliability functions that must continue to be supported by local generation. By 2020, depending on the case, between 10 and 23 percent of natural gas-fired generation in California is produced by power plants associated with the OTC issue.

Reductions were not distributed evenly; at least 70 percent of the gas reductions occurred out-of-state. In-state gas-fired generation only went down by 7 percent in the High Wind case and 10 percent in the High Solar case. In contrast, out-of-state gas-fired generation dropped 21 and 20 percent, respectively. This suggests that out-of-state natural gas is the marginal source of generation for California's net imports and that in-state gas generation is used for local reliability and ancillary services.

The study found that natural gas use increased over time in all 3 cases. However, the amount of natural gas used for electricity generation increased by a smaller amount in the 33 percent cases. See Table 1 below.

Table1: California Natural Gas Use (BCF/day)

	2012	2016	2020	2020 Change from Case 1
Case 1: Reference	2.36	2.57	2.88	
Case 2: High Solar	2.34	2.45	2.52	-12%
Case 3: High Wind	2.34	2.48	2.60	-10%

Generation System Findings

For electricity generation, the WECC-wide amount of natural gas did decrease 15 percent in both 33% cases compared to the reference case, because of the contributions of energy efficiency, rooftop solar, renewables, and CHP.

After OTC replacements were made and the 20% RPS was met, only a few new natural gas plants were needed to meet local capacity and energy needs. These were in the Sacramento, Turlock, and Imperial County areas. The amount of natural gas units added did not change between the 20% case and the two 33% cases. The CHP and energy efficiency additions and the OTC replacement provided sufficient gas flexibility that more units were not needed, even in the more intermittent wind cases.

The study found that average capacity factors for the OTC combined-cycle units trended lower from the 20 percent case to the 33 percent cases. The capacity factors for generic additions and OTC replacement combined cycles, which start out at normal baseload levels in 2012, drop to much lower levels by 2020 for both of the 33% cases, making the long-run cost-effectiveness of these projects questionable.

Combined cycles are usually designed to operate in the range of 60% to 85% capacity factor. This suggests that the sample compliance path we modeled was not optimal if the Scoping Plan amounts of CHP and energy efficiency are added. Thus, a key finding of the study is that none of these policies should be assessed in isolation. Average capacity factors for CTs declined as well, but they were within a plausible range. See Table 2 below.

Table 2: Once-Through Cooling Replacement Generation Annual Average Capacity Factors in 2020

2020	Case 1: Reference	Case 2: High Solar	Case 3: High Wind
OTC Replacement Combined Cycle Average Capacity Factors in Northern California	61%	20%	23%
OTC Replacement Combined Cycle Average Capacity Factors in Southern California	56%	22%	25%
OTC Replacement Simple Cycle Average Capacity Factors in Southern California	17%	15%	15%

More impacts were seen in southern California than northern California. While wind is distributed across the state, solar resources are almost completely concentrated in southern California. OTC units and potential CHP sites are also concentrated in the south. This indicates that there may be more system impacts and potential system stress in the southern transmission grid

Intermittent Renewables Findings

With preferred resource policies built in, the differences between the 33% High Wind and 33% High Solar cases were more modest than they would have been had less ambitious complementary programs been assessed. The study found that a resource mix with a high proportion of wind required more in-state natural gas generation than the High Solar case. This is consistent with the need to use gas-fired units for local reliability and the expectation that wind needs more intermittency support than does solar given its daily load profile and greater variability.

Question 5. Uncertainties

The uncertainties in this study include the load forecast, energy efficiency projections, the CHP target, OTC retirement, and level of OTC replacement.

The principal uncertainties are:

- Whether the post-2007 recession will lower future load and change the structure of the economy.

- The degree to which the targets of 34,707 GWh of energy efficiency load reductions incremental to the 2007 load forecast are achievable by 2020, and whether the load profile changes will be as modeled.
- The degree to which the CHP target of an incremental addition of 32,000 GWh will be achieved by 2020 and what the effect of the economic changes and limited availability of criteria air pollution emission credits will have on construction of new fossil-fired facilities.
- Whether the OTC sample compliance path modeled is representative of the final OTC implementation plan. If not, what the impact of alternative designs of the renewable portfolio will be on other natural gas units.
- Whether major storage technologies develop that provide alternative cost-effective sources of ancillary services.

All outlooks are subject to uncertainties about price trajectories, external system shocks, and potential federal, state or local regulatory modifications.

A further set of analytic uncertainties stem from model performance and quality of input data. Since staff's production cost model does not address ramping, it may underestimate the amount of back-up generation needed.

Question 6. Lessons for implementing a high level of renewables

After including energy efficiency, CHP, and rooftop PV to levels beyond the IEPR 2007 forecast of retail sales, 45,000 GWh of incremental renewables were needed to reach 33 percent by 2020 compared to 74,000–75,000 GWh added in studies that do not include the Scoping Plan's goals. The study found that three-fifths of the electricity savings impacts from achieving Scoping Plan resource goals came from energy efficiency, rooftop PV, and combined heat-and-power while two-fifths of the savings came from renewables. A key finding of the study is that none of these policies should be assessed in isolation.

Question 7. Recommendations for further analysis

Study results indicate that at least three areas deserve further research because the assumptions made in this study have a major impact on whether intermittent renewables influence the type of proxy natural gas unit needed to firm and total fuel use. First, alternative levels of CHP should be tested, as the addition of so much baseload power in-state and in Southern California may be difficult to achieve with existing emission credit problems and the lack of a mechanism to make it happen.

Second, alternative assumptions about compliance with OTC mitigation requirements should be tested because the interactions of all the Scoping Plan programs lead to unrealistic capacity factors in the new combined cycles by 2020. Third, further work in understanding over-generation is needed. Over generation occurs when more generation is provided than load is available to consume it and generation is backed-down in an uneconomic manner.

Question 8. Input assumptions matrix for comparing studies

Load Forecast	CA: Final IEPR 2007 Rest of WECC: Ventyx Spring 2008.
Additional Renewable required	CEC 2020 retail sales forecast. Reduced by additional amounts of EE, CHP, & DG resulted in 77,950 GWh requirement.
RPS in rest of WECC & fossil generation for OTC replacement & intermittent backup	Rest of WECC would meet RPS. In CA, generic fossil capacity of 7,758 MW to replace OTC. Capacity added to meet PRM, not back up renewable.

Assumed Transmission Expansion:

Case	Name	Year / Capacity
All	Sunrise	2016 / 3,000 MW
All	Green Path / Green Path North	2020 / 1,000 MW
All	Palo Verde – Devers ll	2016 / 1,200 MW
High Wind	B.C. – NP 15	2020 / 3,000 MW

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