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QUANTIFYING THE AIR POLLUTION EXPOSURE CONSEQUENCES OF DISTRIBUTED ELECTRICITY GENERATION

Final Report

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Note Concerning Revision

Subsequent to the original version of this report being made publicly available, the authors discovered an error in the model inputs of population density. While none of the qualitative results and conclusions were affected by this error, the absolute value of intake fractions and intake-to-generation ratio were overestimated by a constant factor of 2.59 (representing the conversion from square kilometers to square miles). The error has been corrected in this revised version.

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Abstract

Private sector and governmental organizations have been promoting the deployment of small-scale, distributed electricity generation (DG) technologies for their many benefits as compared to the traditional paradigm of large, centralized power plants. While some researchers have investigated the impact of a shift toward DG in terms of energy use and even air pollutant concentrations, it is also important to evaluate the air pollutant exposure implications of this shift. We conducted a series of case studies within the state of California that combined air dispersion modeling and inhalation exposure assessment. Twenty-five central stations were selected and five air pollutant-emitting DG technologies were considered, including two that meet the 2003 and 2007 California Air Resources Board DG emissions standards (microturbines and fuel cells with on-site natural gas reformers, respectively). This investigation has revealed that the fraction of pollutant mass emitted that is inhaled by the downwind, exposed population can be more than an order of magnitude greater for all five DG technologies considered than for large, central-station power plants in California. This difference is a consequence mainly of the closer proximity of DG sources to densely populated areas as compared to typical central station, and is independent of the emissions characteristics of the plants assessed. Considering typical emission factors for the five DG technologies, the mass of pollutant inhaled per unit electricity delivered can be up to three orders of magnitude greater for DG units as compared to existing California central stations. To equalize the exposure burden between DG and central station technologies, DG emission factors will need to be reduced to a range between the level of the cleanest, new central stations in California and an order of magnitude below those levels, depending on the pollutant and siting. We conclude that there is reason to caution against an unmitigated embrace of DG technologies that emit air pollutants so that they do not pose a greater public health burden than the current electricity generation system.

I. Introduction

Electricity generation has major impacts on the environment at local, regional and global scales. The electric power sector in the United States (US) is heavily combustion-based, contributing significantly to emission inventories of many criteria and hazardous air pollutants (Figure 1). The share of total emissions in California is lower (Table 1) owing to tighter environmental regulations, fuel switching and a high percentage (slightly less than half) of non-emitting generation (CEC, 2001a). Nevertheless, electricity generation's contribution to California's statewide emissions from combustion-related activities remains substantial (Table 1).

A long history of concern about such emissions has led to significant improvements in the polluting characteristics of electricity generation across the nation (EPA, 2004a). Both absolute and relative emissions have decreased significantly over the last few decades, especially in California (CEC, 2003). For instance, the contribution of electricity generation to total statewide nitrogen oxides (NO_x) emissions fell from 7% in 1980 to 2% in 1990 and then remained at 2% in 2000 despite a declining base of total emissions (Scheible, 2002). Multifaceted control programs involving cleaner fuels, improved combustion, and emission control devices are largely responsible for the improvements. Tall stacks have been used as an additional control technique aimed to reduce ground-level pollutant concentrations, especially for larger units.

Electricity is generated by many technologies with diverse characteristics. California's electricity generation units are diverse, both in fuel-type (Figure 2) and size. However, total electrical output and emissions are concentrated in the largest plants. Of approximately 1000 units, the 100 largest, with capacities of over 100 megawatts (MW) each, constitute nearly 75% of the total generating capacity in the state (CEC, 2001c). In addition, 20% of the total 2000 NO_x emissions from electric utilities in California come from the ten largest fossil-fuel burning plants (EPA, 2003a). Thus, individual power plants can be large local and regional sources of air pollutants.

Combustion-based technologies represent over 70% of total power production in the US (EIA, 2004; EPA, 2003a) and are the source of almost all direct air pollutant emissions from electricity generation (EPA, 2003a). [1] We focus our assessment on units that burn natural gas because natural gas is a popular fuel choice for existing and new capacity, especially in California. Forty-five percent of electricity production and 53% of current capacity in California is provided in natural gas-fueled plants (CEC, 2001b and CEC, 2002a). Since 1999, 100% of licensing applications approved by the California Energy Commission (CEC) are for natural gas facilities, mainly combined-cycle (CEC, 2002b). However, we also assess power plants burning other fuels, including oil, landfill gas, and diesel.

For most of the past century, the United States used a regulated monopoly model for ensuring reliable and adequate production of electricity at reasonable cost. Since the mid-1990's, many state legislatures, including California's, have significantly restructured the electric power industry within their jurisdictions. This restructuring has led to increased competition and has reduced central planning and large infrastructure investments.

[1] Hydrogen sulfide emissions from geothermal plants provide the only major exception.

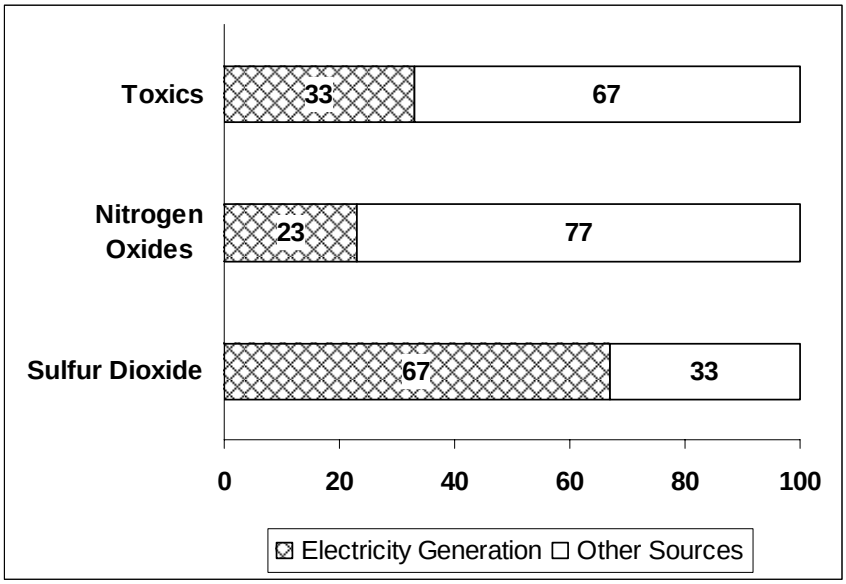

Figure 1. Percentage of total US emissions released by fossil-fuel electricity generation units and other sources in 1999. (Toxics data source: EPA, 2002; others: GAO, 2002)

Table 1. Selected 2000 emission inventory data (tons per day, annual average) for California.

Emission Source	ROG[a]	CO[b]	NO_x[c]	SO_2[d]	PM_{10}[e]
Electric utilities	4.3	32	46	3.8	5
Cogeneration	4.1	38	33	2.1	3.6
Total electric utilities plus cogeneration	8.4	70	79	5.9	8.6
Total stationary fuel combustion	41	295	494	57	43
Total statewide	3311	21035	3591	333	2403

[a] ROG = reactive organic gases [b] CO = carbon monoxide

[c] NO_x = oxides of nitrogen [d] SO_2 = sulfur dioxide

[e] PM_{10} = particulate matter less than 10 μm in diameter

Source: CARB, 2000a.

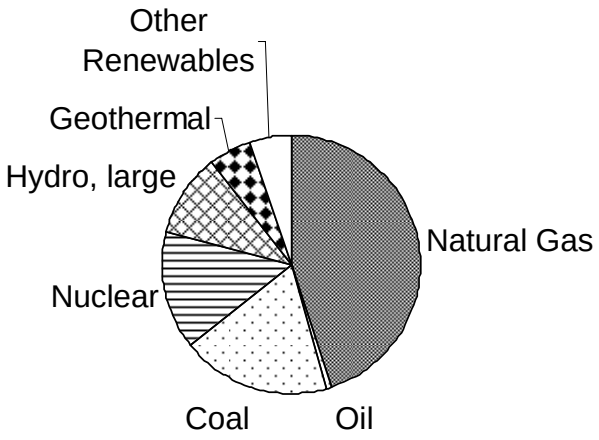

Figure 2. Fraction of 2001 California electricity production (GWh) by fuel-type, with imports allocated to fuel-type category.
Source: CEC, 2001b.

Parallel with this change have been advances in electric generation technology leading to a wave of new, smaller-scale generators on the market. Because of their size and proportional cost, smaller-scale technologies present a greater opportunity for private ownership of power production, heralding a shift towards more distributed generation of electricity.

Formally, distributed generation, or DG, can be defined as, "electric power generation within the distribution network or on the customer side of the meter" (Ackermann *et al.*, 2001). Operationally, any electricity generated "near the place of use" is known as distributed generation (SB 1298, 1999); this is the definition used in this report since it is codified in California law and regulation. The alternative paradigm of electricity generation is referred to as "central station." This model is illustrated in the extreme by 1,000-megawatt (MW) or greater utility-owned power plants, which were mostly constructed in the middle of the last century. California has twelve major central stations, each having a generating capacity of 1,000 MW or greater (CEC, 2001c). The California Energy Commission is the lead agency in permitting of any plant over 50 MW in capacity. Reflecting the concern that plants over 50 MW should be considered in a statewide rather than local context, we operationally use the threshold of 50 MW to define central stations in this report.

Central station power plants are classic "point sources" for air quality engineering and regulation. They provide power to the electrical grid to be used anywhere that transmission lines can connect them to a demand. Size (or capacity) of DG plants is actually not limited by the above definitions, although in practice, entities generating electricity for their own needs seldom produce more than 50 MW. More typically, DG units have less than 1 MW capacity. Table 2 further summarizes some of the differences between DG and central stations that are especially relevant to human exposures to air pollutants.

Distributed generation can include both mature and new technologies, and can use a range of primary energy sources, including fossil fuel combustion and renewable resources. In some circles, DG refers only to small-scale, renewable energy systems (e.g., photovoltaic and wind systems). The focus of this report is on the DG technologies that emit air pollutants, including combustion-based sources (mostly utilizing fossil fuels but also "opportunity fuels" such as landfill gas) and fuel cells with on-site natural gas reformers.

Efficiencies and emission rates of DG units can also vary considerably (Table 3). These characteristics are influenced by many factors, including power rating, fuel type, combustion conditions, and whether and what kind of control technologies are installed. The technologies listed in Table 3 represent the range of units deployed today and that are likely to be installed in the future. Far from all DG technologies being "small, clean and beautiful" — a common misperception — many emit pollutants at higher rates (per unit of electricity delivered) than typical central station plants. Thus, depending on the extent and mix of DG technologies utilized, criteria and hazardous pollutant emissions could increase compared to emissions from the current electricity generation system.

Table 2. Typical characteristics of the central station and distributed generation (DG) paradigms of electricity generation relevant to air quality and inhalation exposure.

Electricity Generation Paradigm	Capacity (MW)	Location	Effective Stack Height (m)[a]	Applicable Emission Regulations
Central Station	Typ. > 50	- Rural - Suburban - Coastal urban	50 – 450	Many
DG	Typ. < 1	- Suburban - Urban	1 - 50	None yet

[a] Effective stack height is discussed in section II.C.4.b; for DG, the range is defined by placement of the unit either on the ground or on the top of a building. Central station effective stack heights are calculated based on an assessment of plume rise (owing to exit velocity and temperature) plus physical stack height.

Table 3. Efficiencies and emissions factors[a] of selected distributed generation technologies.

Characteristic	DG Technologies					1999 California Average (air pollutant-emitting sources)
	Diesel ICE[b]	NG ICE[b]	Microturbine	Fuel Cell (High Temp.)[c]	Fuel Cell (Low Temp.)[c]	
Efficiency	44%	35%	25%	48%	36%	38%
NO_x emissions (g/kWh)	8	2	0.3	0.03	0.03	0.3
PM_{10} emissions (g/kWh)	1	0.2	0.04	0.02	0.03	0.1

Sources: Samuelsen *et al* ., 2003; CEC, 2003; Ghanandan, 2002.

[a] Emission factors for ICEs are pre-2003 CARB emission standard (CARB, 2002), microturbines are post-2003 and fuel cells post-2007 standard.

[b] ICE = internal combustion engine.

[c] With on-site reformer converting natural gas to hydrogen.

There are many potential benefits of the use of DG to society. These include reduced grid congestion; increased overall efficiency of providing electrical and thermal energy through maximal use of waste heat in combined heat and power (CHP) applications; reduced losses from long-distance transmission of electricity (line losses); and deferred siting and construction of new central station plants. Focusing on these benefits, the US Department of Energy (DOE) has established a goal that "[by] 2010 … distributed energy resources [will] achieve 20% of all new electric capacity additions in the US" (DOE, 2000). [2] At the time of adopting this recommendation, DOE translated 20 percent of new capacity additions to 26.5 gigawatts (GW) and the agency has initiated programs to meet that goal. The California Energy Commission, after deciding that more analysis was prudent before setting a numerical goal, has published a strategy that calls for promotion of DG technologies within the state (CEC, 2002c).

Already, the DOE estimates that more than 53 GW of distributed energy resources are installed in the US (DOE, 2000). [3] The CEC estimates that greater than 2.0 GW of DG is installed in California with another 3.0 GW of emergency back-up generation (often undifferentiated in definitions of DG even though back-up power is not considered DG by most authorities). From January 2001 through May 2002, 400 MW of new capacity were proposed in California (CEC, 2002c). By far, the majority of these installations are household-sized, renewable energy units; however, as with central stations, most of the capacity is in the larger units of up to 50 MW (DOE, 2000 and CEC, 2002c).

In addition to overall societal benefits, there are many commercial benefits of DG driving its adoption. During the California energy crisis of 2000-2001 and before, the cost of self-generation was substantially lower than the retail cost of electricity, mainly due to the low cost of natural gas. Today, the most economical configuration is to identify nearby heat loads that can take advantage of the waste heat of electricity generation in combined heat and power operations (formerly known as co-generation). However, "premium power"— i.e., supplying very reliable, high quality power to high-value activities such as the operation of critical electronic equipment — is emerging as a primary market niche for DG applications (CEC, 2002c).

Ironically, one attribute that makes DG innovative and appealing to many parties — that the generation units are sized appropriately to the local demand — causes concern to many regulators. Their small size places most DG units outside of most existing regulatory structures, which have focused on large, central station sources. For criteria pollutants, the US Environmental Protection Agency (EPA) sets standards for ambient concentrations to be protective of public health, including susceptible subpopulations. To ensure that these standards are not exceeded, the states determine the maximum amount of certain primary pollutants that can be emitted by various source classes, as well as

[2] The US Department of Energy defines "distributed energy resources" (DER) to mean supply- and demand-side resources. However, by referring to DER as supplying "20 percent of new electric *capacity*" (emphasis added) it would seem that they use this term synonymously with the definition of DG as a supply-side resource, as used in this report (DOE, 2000).

[3] This estimate includes units used solely for back-up, peaking, or baseload power and may include an estimate of demand-side resources.

other measures (Kyle *et al.*, 2001). The states (or their decentralized designees) then allocate, in the form of permits, the total allowable emissions to all regulated sources. [4]

For hazardous air pollutants (HAPs), the EPA uses technology-based regulations to achieve a risk-based goal. The EPA determines which industries or activities constitute "major sources" of a particular HAP and then require that specific control technologies be used to limit those emissions. Through this approach, the EPA attempts to reduce to acceptable levels the long-term health risk owing to ambient exposure to these pollutants (Clean Air Act, 1990).

Large point sources are a major focus of both of these regulatory programs because they have traditionally constituted the majority of total emissions and because they are easier to regulate. To identify these large sources in the electricity generation sector, regulators often use the power rating (e.g., horsepower, hp) or electricity generation capacity (e.g., kilowatts, kW) of a plant. Generally, the air quality management districts (AQMD) in California have exempted from permit requirements electricity generation units that are smaller than 50-100 hp or 300 kW (CARB, 2001a). This threshold has the effect of exempting most DG units.

Alternatively, some AQMDs in California use mass emission rates[5] on which to base exemption decisions. Mostly, these rules exempt units that emit less than a certain mass emission rate for the sum of all emitted pollutants; one AQMD specifies a mass emission rate for the sum of all criteria pollutant emissions (CARB, 2001a). Regardless of the particular configuration of the exemption standards, total emissions from most DG units are below *de minimus* levels and therefore are not subject to emission limitations from these types of regulations.

Like all combustion-based electricity generation technologies, DG units emit both criteria and hazardous air pollutants. Central station plants located in California often trigger health risk assessment requirements — such as those from the "Hot Spots" program (AB 2588, 1987) — based on the quantity of their emissions. Because the total mass emitted by any individual DG unit is low, the likelihood that it would trigger a risk-based regulation is similarly low. Thus, as yet, most DG units are not subjected to emissions limitations based on the risk they pose to surrounding populations.

Nevertheless, some regulatory attention has focused on the potential air quality impacts of the anticipated increased prevalence of DG. First, the CEC placed an important caveat onto their DG mission statement, promising to promote and deploy DG technologies only "…to the extent that such effort benefits energy consumers, the energy system and the environment in California" (CEC, 2002c). This statement explicitly acknowledges the potential environmental and public health burden imposed by the expanded use of current DG technologies.

This concern can be traced back to 1999 when the California Senate, concerned that the emission factors for certain DG technologies could be more than an order of magnitude greater than those for central station units, passed Senate Bill 1298 (SB 1298, 1999). This legislation instructed the California Air Resources Board (CARB) to establish a certification program for all DG units that are exempt from district emission rules. In two stages, the program will regulate mass emissions per unit of electricity

[4] Sometimes these permits are in the form of total mass emission limits and sometimes in terms of mass emission rates (mass per unit time) or emission factors (mass per unit electrical output).
[5] Expressed in terms of mass per unit time, not per unit electrical output.

generated (SB 1298, 1999). All new DG units installed after 2003 are required to meet the best performance achieved in practice by any DG technology. By 2007, CARB will require that all new DG units achieve parity with central stations equipped with the best available control technology (BACT[6]) (CARB, 2002). In this way, CARB is seeking to make newly installed DG no worse for air quality in terms of emission factors than would be a new central station plant.

Most prior research related to the environmental impact of DG has been aligned with CARB's approach, focused on assessing the potential for increased air pollutant mass emissions into particular air basins or states from widespread deployment of DG (California: Iannucci *et al.*, 2000; Allison and Lents, 2002. Texas: Hadley and Van Dyke, 2003. Mid-Atlantic states: Hadley *et al.*, 2003a; Hadley *et al.*, 2003b. New York: Williams *et al*., 2003). The implicit assumption is that a given mass emitted from DG sources poses the same potential for adverse health consequences as an equal mass from central stations, an assumption our preliminary research has suggested is invalid (Heath *et al.*, 2003). Other recent research has been motivated by a concern for the ability of localities, air basins and states to meet the National Ambient Air Quality Standards (NAAQS) and other mandates with increased use of DG. Medrano *et al.*, (2003) used an Eulerian airshed model to predict primary and secondary criteria pollutant concentrations under different scenarios of widespread DG deployment in the South Coast Air Basin (SoCAB). Based on preliminary modeling, they found that criteria pollutant concentrations could change both nonuniformly and nonintuitively throughout the SoCAB, and could lead to significant concentration increases under certain deployment scenarios (Medrano *et al.*, 2003; Samuelsen *et al.*, 2003).

An important factor in any assessment of the environmental impacts of DG is the potential effects of DG emissions on population exposure to air pollutants. Central-station power plants emit pollutants from tall stacks, often remotely located from population centers. DG technologies emit their pollutants closer to the ground, typically in more densely populated regions. Closer proximity between emissions and people can cause greater exposures and therefore greater health risk from pollutant emissions, even if the total mass emitted is unchanged.

The aim of this report is to explore the effects of a shift in release location on human inhalation intake of pollutants emitted from baseload electricity generation facilities. We use this information to provide an estimate of the emission factors necessary for DG technologies to equalize the exposure burden of comparable central station facilities. To accomplish these objectives, we use a common air dispersion modeling method to compare estimates of the annual-average population intake of pollutants emitted from the two paradigms of electricity generation: distributed generation and central station. This study contributes to a better understanding of the implications of a fundamental shift in the range and scale of technologies used to generate electricity. The results will also suggest fruitful directions for future research to substantiate and refine our findings. This research builds on the work of others who have looked at the question of population intake from central stations (Levy *et al.*, 2003; Li and Hao, 2003; Zhou *et al.*, 2003; Evans *et al.*, 2002; Levy *et al.*, 2002a; Levy *et al.*, 2003; Nigge, 2001; Smith, 1993). This report substantially extends their analyses by

[6] The same acronym, BACT, is used in the context of California and US regulations. Throughout this report, "BACT" refers to the California BACT standard.

considering DG technologies and by incorporating technological differences (e.g., emission rates, efficiencies and line losses) between and among various DG and central station technologies. It also extends their work to consider the specific case of California, a coastal state with considerably different meteorology and population distribution than found elsewhere in the United States. California is an important case because it has been a leader in the adoption of DG technologies and is already faced with severe air quality problems. In addition, important regulatory decisions regarding the entrance of DG into the electricity generation market in California and elsewhere are scheduled to be made in the next few years.

II. Methods

We selected a broad sample of existing and hypothetical electricity generation stations in California to explore how a paradigm shift in the scale of electricity generation might affect population exposure to air pollutants. Our 37 cases of existing electricity generation units (EGUs) capture much of California's diversity in fuel, technology and location. Contrasted with the existing units, we model 48 cases of hypothetical DG units, investigating many different technologies, fuel and siting options. Within these two broad groups, we focus our comparison between existing central stations and small-scale DG units located in the urban core. Not only does this contrast highlight the difference in exposure potential between the two paradigms in the extreme, but it also is the most likely scenario of how and where DG could transplant central stations.

For each case, we model the plume of air pollutant emissions across 8760 hours representing a typical annual meteorological cycle for that region of California. This process yields hourly estimates of downwind concentrations of certain pollutant species and the inhalation intake by the exposed population within 100 km from the source. The exposure results for calculated hours are averaged to obtain an estimate of annual-average population intake. Dividing this value by the mass emitted reveals the fraction of emissions that is inhaled by the downwind population. This figure, called the intake fraction, is a useful metric for comparison of the exposure potential of different sources across widely divergent scales of EGUs.

Our primary metric in the comparison of the exposure consequences of electricity generation paradigms in California is the intake-to-generation ratio (IGR). The IGR is the ratio of the pollutant mass inhaled by the downwind population per kilowatt-hour delivered to the place of use. We use the intake-to-generation ratio to estimate emission factors for new DG units that would be necessary to equalize the exposure burden amongst combustion-based sources of electricity generation.

The cases we consider differ along a number of key dimensions: population density, stack height, meteorological conditions, and pollutant class. These dimensions substantially influence the outcome of the population exposure assessment. Other characteristics (such as fuel and technology) are also varied to make the cases representative of the range of electricity generation facilities in California. Although not exhaustive, this case-study approach provides important information about the differences in exposure that should be expected from different electricity generation methods. The exploration also provides information about the causes of those differences and suggests directions for future research that could be used to test and refine these results.

II.A Case Selection and Background Information

Broadly, we considered cases in two categories, referred to as existing units and hypothetical DG. In the first category, we selected 37 existing electricity generation units to represent the diversity in the current stock of California EGUs along a number of dimensions, including capacity, location, fuel, and generator technology. Within this category, we focus on 25 central station plants that represent the backbone of California's electricity generation system. In addition, we consider two other types of existing generation: cogeneration and existing distributed generation (> 1 MW). Definitions of each type are provided in section II.A.1.

The second category comprises two types of small-scale (< 1 MW) hypothetical DG units in two classes of technologies. Many proponents of DG believe that the scale, modularity and favorable economics of DG technologies, as well as urban transmission infrastructure and capacity constraints, will lead to the increased prevalence of electricity generation in the urban core where existing sources have not typically been sited. We model these sources in the downtown of large cities at the address of their city hall. The second type consists of units co-located at the sites of the existing units. Keeping meteorology and the surrounding population distribution constant, these cases principally explore the exposure impact of decreasing the release height. We considered two classes of technologies hypothetically installed at both the city hall and co-located sites: those that were installed before 2003, which would not have to meet CARB's emission regulations (e.g., natural gas and diesel internal combustion engines (ICE), and natural gas turbines) and those technologies that have been certified as meeting the 2003 or 2007 emissions regulations (i.e., microturbines and fuel cells).

A summary of various categories and inclusion criteria we use to define our cases is provided in Table 4 for existing units and Table 5 for hypothetical DG. The following two sections detail the criteria we applied in selecting the existing units and hypothetical DG technologies modeled as well as background information on each of the cases.

II.A.1 Case Selection Criteria

II.A.1.a Existing Units

Basic inclusion criteria for the selection of existing units were applied first to the list of all California EGUs found in EPA's eGRID database (EPA, 2003a). To be eligible, EGUs had to meet all of the following conditions:

- be located within California
- be a combustion-based source
- have non-zero emissions and generation.

eGRID reporting year 1999 was used to match the latest available emissions data from the EPA's 1999 National Emission Inventory (NEI) for criteria and hazardous air pollutants (EPA, 2004b and 2003b, respectively).

All eligible sources were then categorized into three types – central station, cogeneration and existing DG – using the following definitions. Central stations are defined as any plant of over 50 MW on-line capacity that did not report any heat

production in 1999 in eGRID (i.e., are not cogeneration plants). [7] The 50-MW threshold is used by the CEC to determine which plants are large enough to warrant regulatory review by the state. Thus, it is a convenient definition for which plants are truly centralized sources providing power to the grid as opposed to a more local demand. We do not allow plants with simultaneous heat production since there is a separate category for cogeneration plants. Out of 85 combustion-based plants over 50 MW, approximately 45 were non-cogeneration, and were further considered in this category.

Existing distributed generation sources are more difficult to identify. There are no data to operationalize our preferred definition of DG – "electricity generation close to the place of use" – as we cannot determine whether electricity is sold to the grid or is used locally. Another common DG definition – electricity generation within the distribution network (e.g., Ackermann *et al.*, 2001) – was not practical to investigate since it would require detailed information about individual units not centrally recorded. A capacity criterion has been used by other authors to define DG (see Ackermann *et al.*, 2001). Though not precise, we define existing DG as those units below 10 MW on-line capacity, of which there are 26 that are non-cogeneration. Because only those EGUs over 1 MW capacity are federally regulated (Greene and Hammerschlag, 2000) and thus reported in eGRID, in effect our existing DG category represents cases of relatively large DG. We will refer to this category as "existing DG (> 1 MW)" to distinguish it from the smaller-scale technologies that define much of the anticipated wave of new DG.

The cogeneration category is defined as any source that reports both heat and electricity production for 1999 in eGRID, encompassing 188 eligible sources. There is no capacity restriction in this category.

Table 4 summarizes the above types, definitions and number of eligible plants.

After all plants that met the basic inclusion criteria for their eGRID listings were categorized, we used an iterative process of preliminary selection based on further eGRID criteria and determination of eligibility based on a set of NEI-based inclusion criteria. The number of plants selected was determined separately for each type. All central stations meeting the above criteria were eligible. For both the cogeneration and existing DG categories, our primary objective was to capture the diversity of combustion fuel in these source types. Thus, we selected one cogeneration and one existing DG plant to represent each primary fuel; if there was more than one plant within a certain fuel category, we randomly selected from amongst all eligible. While focusing on fuel type, we were also attentive to achieving diversity in terms of location and generator technology.

Any preliminarily selected plant had to meet the following conditions based on its listing in the NEI:

- can be unambiguously identified in both the criteria and hazardous air pollutants NEI databases;

[7] Upon further inspection of the eGRID data, it became apparent that in some cases, plants that are normally cogeneration units occasionally do not produce heat in a given year. The CEC 2001 Powerplant Database (CEC, 2001c) reports whether a plant is considered a cogeneration plant generally, not relying on any particular year's heat production data. Thus, to avoid any ambiguity as to whether a source is normally cogeneration but simply didn't report heat production in 1999, we also remove any plant listed as a cogeneration unit in the CEC 2001 Power Plant Database (CEC, 2001c). For similar reasons, we also disallow any plant that lists a cogeneration Source Classification Code (SCC) in the NEI.

- has at least one electricity generation or cogeneration Source Classification Code (SCC)[8]; and
- nearly all emissions from all boilers/ICEs have to be classified for electricity generation as opposed to other industrial/commercial purposes.

The first criterion in this list resulted from difficulty in identifying the corresponding entries in the NEI for eGRID entries. There is a one-to-many relationship between plants listed in eGRID and their corresponding NEI listings because multiple agencies are allowed to contribute non-duplicative emissions information for a single source. This challenge is compounded by the fact that many large organizations, such as the three investor-owned utilities in California, often list their EGUs under the generic parent company name (e.g., So Cal Edison) where the only distinguishing feature between entries is the address, which is not provided in all cases. Since eGRID only reports a plant's county name for its location, we employed the CEC's 2001 Power Plant Database to gain an address, as well as owner and operator names. By using both eGRID and CEC databases, we were able to aggregate enough unique information to unambiguously identify most eGRID entries. Additionally, we mapped all identified EGUs along with the generically named stations that provided no street address to ensure that no obviously corresponding source was missed. This plotting procedure employed ArcGIS (ESRI, 2002) using the geographic coordinates provided in the NEI.

The reason for selecting only plants where electricity generation/cogeneration SCCs represent all or nearly all of any boiler/ICE-related emissions is to avoid underestimation of emissions. For instance, owing to concerns about the reliability of user-input SCCs, if a cogeneration source has industrial or commercial boilers that emit a substantial fraction of total emissions of some pollutant, we are concerned that some emissions classified as non-cogeneration might actually be cogeneration-related. Thus, some plants otherwise eligible were eliminated. Unfortunately, even using this method, the emissions from the cogeneration plants are suspect (see section II.C.4.b).

After application of the above criteria, 25 central stations remained to model. The 188 cogeneration units represented twelve fuels (150 units burn natural gas), but only six fuel-types had units that met all of the above criteria. The 26 existing DG (> 1 MW) units represented four fuels, only three of which had sources that met the above criteria. To increase the number of cases in this category, we increased the selection of landfills to four, making six total cases of this type. Further information on these cases is presented in section II.A.2.

[8] Source Classification Codes are used by the EPA to categorize the technology, fuel and industry of an emission process. For instance, consider the case of external combustion boilers. SCCs identify whether the boiler is used for producing electricity or for some other industrial or commercial/institutional process. SCCs also identify the fuel consumed (natural gas, landfill gas, digester gas, diesel fuel, etc.). Finally, SCCs can also identify more specific attributes of the technology, for example whether the boiler heat rate is greater or less than 100 MMBtu/h, or what type of firing is used (e.g., tangential, normal, wall). Finally, SCCs also specify whether the unit produces solely electricity or also heat (i.e., cogeneration). Since the SCCs, as with all data in the NEI, are based on user inputs, they are not completely reliable, but nevertheless provide the most detailed information about emitting technologies available.

Table 4. Summary of the "existing units" category of cases.

Type	Abbreviation	Definition	Source Classification Codes	No. Eligible Based on Definition[a]	No. Selected to Model[b]
Central Station	CS	> 50 MW not cogen	Any electricity generation	45	25
Cogeneration	Cogen	Produces heat and power	Any cogeneration	188	6
Existing DG (> 1 MW)	DG (> 1 MW)	< 10 MW not cogen	Any electricity generation	26	6

[a] All existing units had to be combustion-based, in addition to the definitions listed in the table.

[b] Several other inclusion criteria based on a plants listing in the EPA's National Emission Inventory were applied before the final determination of how many to model in each category.

II.A.1.b Hypothetical DG Cases

Hypothetical DG sources represent two location types and two classes of DG technologies. Because an important niche for DG is to provide on-site power to large, commercial buildings, we considered units installed at the city halls of the eleven most populous cities in California. We chose city halls for siting because they are easily identifiable landmarks and are typically located in the downtown core. The second type of hypothetical DG source is co-located at the site of each existing unit.

While DG is arguably not limited to any certain capacity (tens of megawatts could be locally used at large industrial sites), most electricity users' demands are less than 1 MW. Thus, the DG technologies modeled are typical of those below 1 MW capacity. We consider technologies most likely to have been installed before CARB's 2003 emission standard as well as ones certified as meeting CARB's 2003 and 2007 emission standard. Internal combustion engines (ICE) and turbines are both mature technologies that represent the largest fraction of installed DG in the US and California (CEC, 2001c; EPA, 2003a). The two most popular fuels for ICEs are diesel and natural gas; natural gas is the most popular fuel for turbines. Thus, the three technologies representing the pre-2003 fleet of installed, small-scale DG are diesel and NG ICEs and natural gas turbines (GT).

CARB has certified seven DG products for meeting the 2003 and/or 2007 standard, all them small-scale (< 1 MW) (CARB, 2004a). Three microturbines meet the 2003 standard and four fuel cells meet the 2007 standard. Thus, microturbines and fuel cells are modeled in our post-2003 and post-2007 cases. While the approved fuel cells can operate at both high and low temperatures, we model low temperature fuel cells because these are the most mature technologies (Energy Nexus Group, 2002).

Table 5 summarizes attributes of the hypothetical DG cases.

II.A.2 Location and Background Information of Cases

II.A.2.a Existing Units

In all, 37 existing units met the inclusion and selection criteria: 25 central stations, 6 cogeneration plants and 6 DG units (> 1 MW). Combined, these units represent 32% of the in-state generation capacity of California (CEC, 2001a) and 17% of 1999, California-owned generation[9] (CEC, 2004a). As can be seen in Figures 3-5, these plants are located in most air basins in California. Tables 6-8 reveal that the cases selected represent a total of nine fuel types (including one coal plant), five combustion technologies, and six nitrogen oxides control technologies. The size (capacity) of the plants varies widely, from the largest combustion-based central stations in California (2000+ MW) to systems barely greater than 1 MW. The smaller systems generally utilize "opportunity fuels" such as landfill and digester gas and wood waste. The cases also vary widely in capacity factor, which indicates that these plants are used across the load duration curve, i.e., in peaking, baseload and load-following modes. We model the plants as if they were all baseload. Future work could address the sensitivity of our results to the hour of operation.

[9] 1999 California generation includes California utility-owned shares of nuclear, coal and some firm contract generation in other states (CEC, 2004a).

Table 5. Summary of the hypothetical DG category of cases.

Type	Definition	Technology Classes	Specific Technologies Modeled in Each Class
Co-located	< 1 MW	Pre-2003	Diesel ICE, NG ICE, NG GT[a]
		Post-2003	Microturbine
		Post-2007	Low temperature fuel cell[b]
City hall	< 1 MW	Pre-2003	Diesel ICE, NG ICE, NG GT[a]
		Post-2003	Microturbine
		Post-2007	Low temperature fuel cell[b]

[a] ICE = internal combustion engine; NG = natural gas; GT = gas turbine.

[b] Fuel cell emissions result from the production of hydrogen by the on-board natural gas reformer.

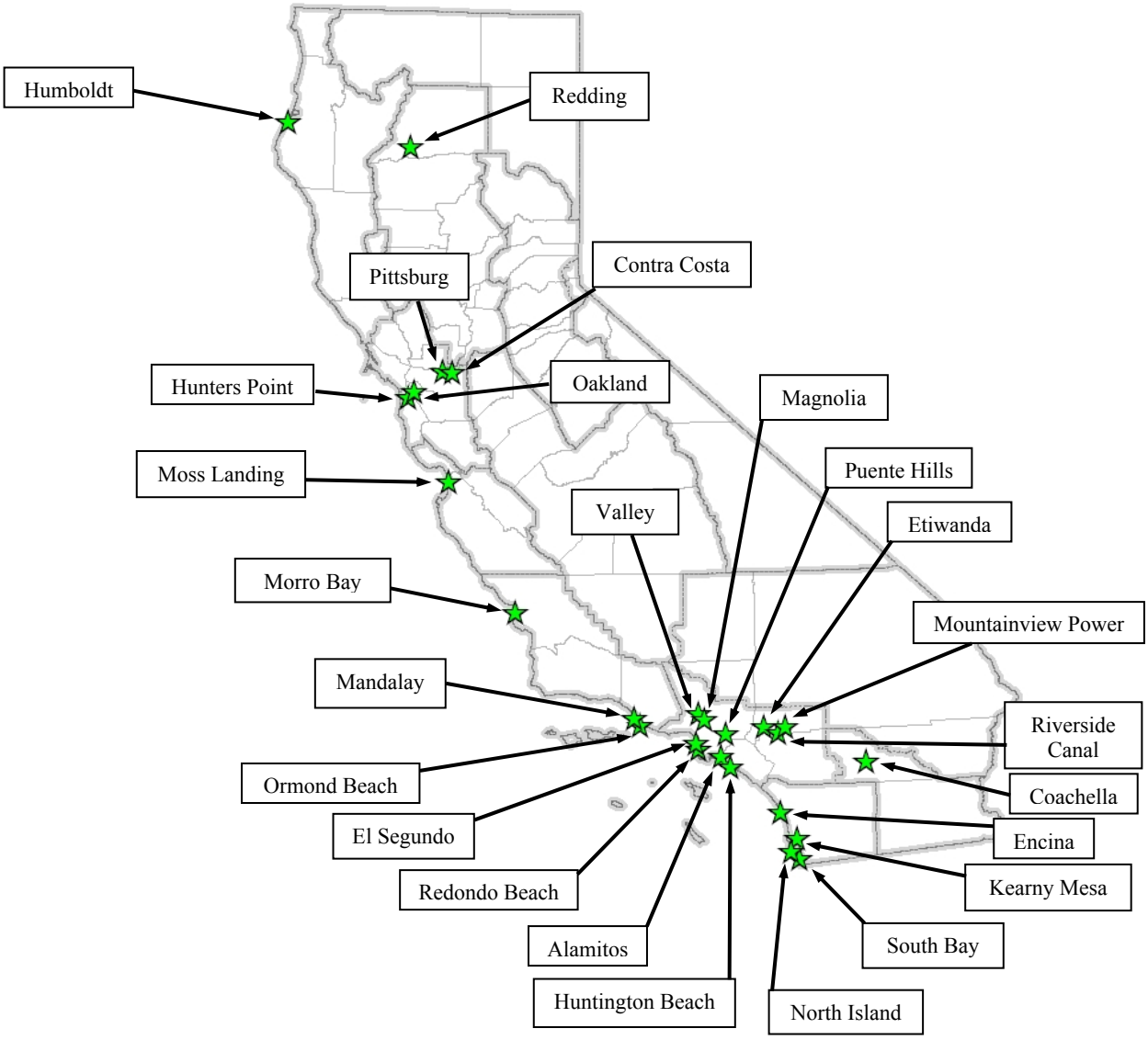

Figure 3. Locations of the 25 central station plants that form part of the existing units category of cases. The smallest geographic entities shown on the map are counties (light, thin borders). The larger geographic entities are air basins (dark, thick borders), which generally follow county boundaries. (Location data from EPA, 2003b.)

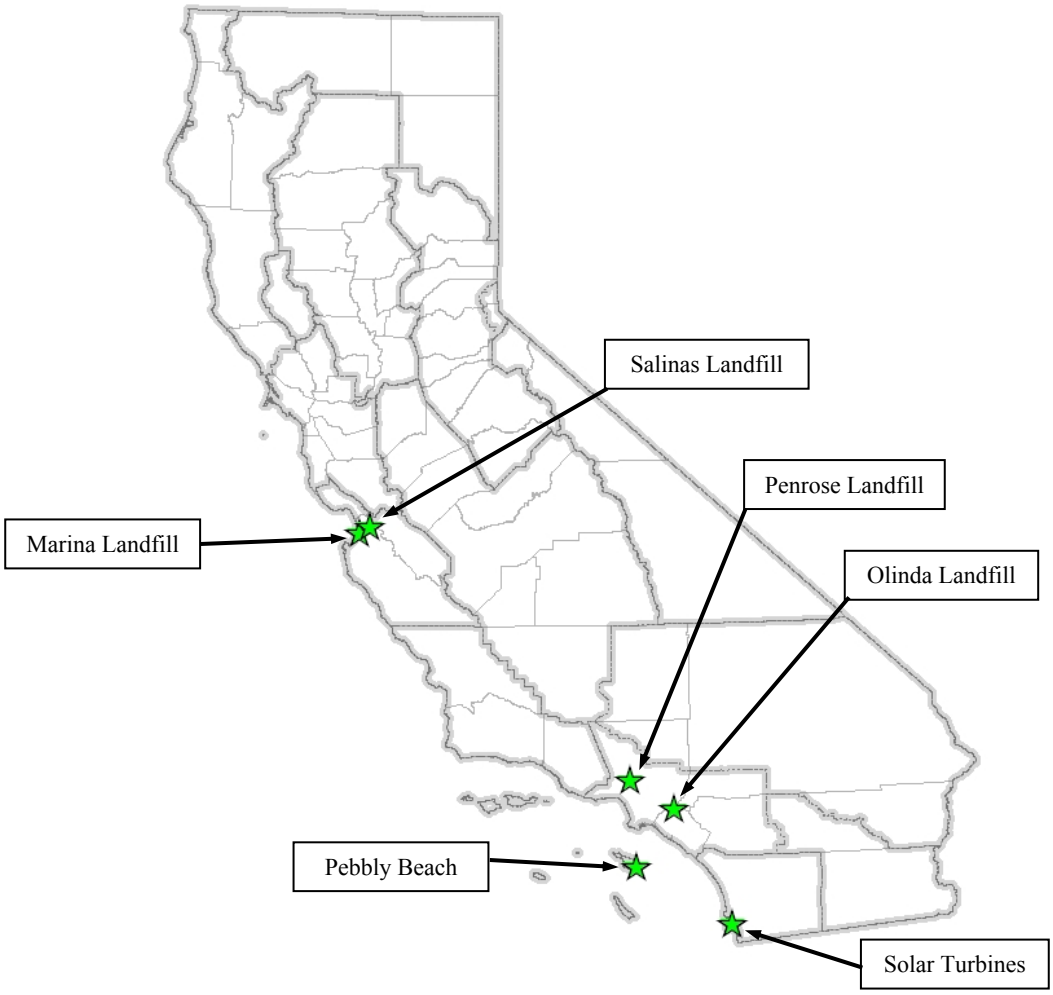

Figure 4. Locations of the six existing DG (> 1 MW) plants that form part of the existing units category of cases. Note Pebbly Beach, which provides power to Catalina Island in Los Angeles Bight. (Location data from EPA, 2003b.)

Figure 5. Locations of the six cogeneration plants that form part of the existing units category of cases. Live Oak and Mt. Poso are in such close proximity that their location markers (stars) overlap. (Location data from EPA, 2003b.)

Table 6. Characteristics relevant to air quality for the 25 central station existing units in 1999.

eGRID Name	NEI Name[a]	County	Capacity (MW)	Fuel[b]	Prime Mover[c]	NOx Control Technology[d]	Capacity Factor	Efficiency[e]	Generation (1000 MWh per y)
eGRID	NEI (HAPs)	eGRID	eGRID	NEI (criteria & HAPs)	eGRID	eGRID	eGRID	eGRID	eGRID
AES Alamitos LLC	1: So Cal Edison Co 2: So Cal Edison; Alamitos Gen St 3: Alamitos	Los Angeles	2129	NG, Diesel	ST(6), GT(1)	BF(2), FR(2), LN(2)	0.18	32%	3,415
Pittsburg Power	1: Southern Energy California, PI 2: Pittsburg	Contra Costa	2029	NG	ST(7)	NA(4), FR(3)	0.28	45%	5,041
Ormond Beach Generating Station	SCE-Ormond Beach Gen Station	Ventura	1500	NG	ST(2)	LN(2)	0.11	32%	1,478
Duke Energy Moss Landing LLC	1: Duke Energy Moss Landing LLC 2: Moss Landing	Monterey	1404	NG, Residual Oil	ST(2)	FR(2)	0.50	35%	6,119
AES Redondo Beach LLC	1: So Cal Edison Co 2: Redondo Beach	Los Angeles	1303	NG	ST(8)	BF(2), SR(2), NA(1)	0.12	33%	1,340
Duke Energy Morro Bay LLC	Morro Bay	San Luis Obispo	1056	NG, Diesel	ST(4)	NA(2), OV(2)	0.33	34%	3,050
Etiwanda Generating Station	Etiwanda	San Bernardino	1049	NG	ST(4), GT(1)	SN(2), FR(2)	0.12	31%	1,124
Encina	1: Encina 2: Cabrillo Power I LLC Encina PO	San Diego	1000	NG, Diesel	GT(1), ST(5)	FR(5)	0.44	41%	3,989
El Segundo Power	1: El Segundo 2: So Cal Edison Co	Los Angeles	996	NG	ST(4)	BF(2), FR(2)	0.36	47%	3,133
Duke Energy South Bay LLC	1: Duke Energy-South Bay Power PL 2: SDG & E Co/South Bay Plant 3: South Bay	San Diego	733	NG, Diesel, Kerosene, Residual Oil	ST(4), GT(1)	FR(2), OV(2)	0.28	32%	1,793
Contra Costa Power	1: Contra Costa 2: Southern Energy California, CO	Contra Costa	718	NG	ST(2)	OV(2)	0.49	45%	3,102
Mandalay Generating Station	1: Mandalay Power Generation 2: SCE-Mandalay Gen Station	Ventura	573	NG, Diesel, Residual Oil	ST(2), GT(1)	FR(1), BF(1)	0.25	35%	1,272

Table 6. con't

eGRID Name	NEI Name[a]	County	Capacity (MW)	Fuel[b]	Prime Mover[c]	NOx Control Technology[d]	Capacity Factor	Efficiency[e]	Generation (1000 MWh per y)
eGRID	NEI (HAPs)	eGRID	eGRID	NEI (criteria & HAPs)	eGRID	eGRID	eGRID	eGRID	eGRID
AES Huntington Beach LLC	1: Huntington Beach 2: So Cal Edison Co	Orange	563	NG, Diesel, Residual Oil	GT(3)	FR(2)	0.18	33%	879
Valley	1: Valley 2: LA City, DWP Valley Generating	Los Angeles	546	NG, Diesel, Residual Oil	ST(4)	BF(2)	0.03	26%	128
Hunters Point	1: Hunters Point 2: PG & E Co, Hunters Point Power	San Francisco	428	NG, Diesel	ST(3), GT(1)	NA(5)	0.18	27%	659
Kearny	1: SDG & E Co/Kearny Mesa GT 2: Cabrillo Power II LLC Kearny M	San Diego	165	NG, Diesel	GT(3)		0.02	43%	30
Riverside Canal Power Co	1: So Cal Edison Co 2: Highgrove	San Bernardino	140	NG	ST(4)	NA(2), LN(2)	0.02	25%	20
Duke Energy Oakland LLC	1: Duke Energy Oakland LLC 2: Pacific Gas and Electric Co, O	Alameda	137	Diesel	GT(3)		0.004	28%	5
Mountainview Power Co LLC	1: San Bernardino 2: So Cal Edison Co	San Bernardino	120	NG	GT(1), ST(1)	NA(2)	0.04	29%	46
Humboldt Bay	1: P G & E-Humboldt Bay Plant 2: Humboldt Bay	Humboldt	102	NG, Diesel, Residual Oil	ST(2)	NA(2)	0.47	43%	426
Redding Power	Redding Power	Shasta	96	NG	ST(1), GT(3)		0.03	23%	29
Coachella	Imperial Irrigation Dist	Riverside	93	NG, Diesel	GT(4)		0.01	25%	10
Magnolia	Magnolia	Los Angeles	88	NG	CC(1), ST(2), GT(1)		0.001	32%	1
Puente Hills Energy Recovery	LA Co., Sanitation District	Los Angeles	53	LFG, Diesel, NG	ST(1), GT(1)		0.83	30%	382
North Island	Cabrillo Power II LLC North Is	San Diego	52	NG, Diesel	GT(2)		0.01	40%	5

Footnotes for **Table 6**

Data sources: eGRID: eGRID2002 Version 2.01 Plant File (Year 1999 Data) (EPA, 2003a).
NEI (HAPs): 1999 Final National Emission Inventory for Hazardous Air Pollutants Version 3, Summary Files (EPA, 2003b).
NEI (criteria): 1999 Final National Emission Inventory for Criteria Pollutants Version 3, California Point Source Files (EPA, 2004b).

[a] If the NEI contained more than one listing for the same eGRID plant, all associated plant names are provided in a numbered list.

[b] Fuel burned based on SCCs listed for electricity generation, in descending order of proportion of emissions due to combustion of that fuel.
NG = natural gas; LFG = landfill gas.

[c] Prime mover types are listed with the number of generators using that technology in parens. CC = combined cycle; GT = gas turbine; ST = steam turbine.

[d] Nitrogen oxides (NOx) control technologies are listed with the number of boilers with the specified NOx control technology in parentheses.
BF = biased firing; FR = flue gas recirculation; LN = low NOx burner; NA = not applicable; OV = overfire air;
SN = selective noncatalytic reduction; SR = selective catalytic reduction.
NOx control technologies are only reported for utility plants.

[e] Efficiency is the efficiency of converting fuel thermal energy to electric energy.

Table 7. Characteristics relevant to air quality for the six DG (> 1 MW) existing units in 1999.

eGRID Name	NEI Name[a]	County	Capacity (MW)	Fuel[b]	Prime Mover[c]	Capacity Factor	Efficiency[d]	Generation (1000 MWh per y)
eGRID	NEI (HAPs)	eGRID	eGRID	NEI (criteria & HAPs)	eGRID	eGRID	eGRID	eGRID
Pebbly Beach	1: So Cal Edison Co 2: So Cal Edison Co	Los Angeles	9.4	Diesel	IC(6)	0.35	29%	29
Penrose	1: Odgen Power Pacific, Inc 2: Pacific Energy-Penrose Landfill	Los Angeles	9.4	LFG	IC(5)	0.91	24%	75
Patio Test Solar Turbines Inc	Solar Turbines - Pacific Hwy	San Diego	8.9	NG, Diesel	GT(2)	0.21	22%	16
Olinda Generating Plant	GSF Energy Inc; Olinda Landfill	Orange	5.6	LFG	IC(3)	0.81	27%	40
Marina Landfill Gas	Monterey Region Waste Mngmnt	Monterey	2.8	LFG	IC(3)	0.91	32%	22
Salinas	1: Pacific Lighting Energy System 2: Ogden Power Pacific Inc - Sali	Monterey	1.5	LFG	IC(1)	0.89	28%	11

Data sources: eGRID: eGRID2002 Version 2.01 Plant File (Year 1999 Data) (EPA, 2003a).
NEI (HAPs): 1999 Final National Emission Inventory for Hazardous Air Pollutants Version 3, Summary Files (EPA, 2003b).
NEI (criteria): 1999 Final National Emission Inventory for Criteria Pollutants Version 3, California Point Source Files (EPA, 2004b).

[a] If the NEI contained more than one listing for the same eGRID plant, all associated plant names are provided in a numbered list.

[b] Fuel burned based on SCCs listed for electricity generation, in descending order of proportion of emissions due to combustion of that fuel.

NG = natural gas; LFG = landfill gas.

[c] Prime mover types are listed with the number of generators using that technology in parentheses. GT = gas turbine; IC = internal combustion engine.

[d] Efficiency is the efficiency of converting fuel thermal energy to electric energy.

Table 8. Characteristics relevant to air quality for the six cogeneration existing units in 1999.

eGRID Name	NEI Name	County	Capacity (MW)	Fuel[a]	Prime Mover[b]	Capacity Factor	Electricity Emissions Allocation Factor[c]	Electrical Conversion Efficiency (power only)	Total Energy Efficiency (heat+power)	Generation (1000 MWh per y)
eGRID	NEI (HAPs)	eGRID	eGRID	NEI (criteria & HAPs)	eGRID	eGRID	eGRID	eGRID	eGRID	eGRID
Live Oak Cogen	Live Oak Limited	Kern	69	NG	GT(1)	0.60	90%	41%	46%	259
Mt Poso Cogeneration	Mt Poso Cogeneration Company	Kern	62	Coal (Bituminous)	SF(1)	0.53	91%	29%	31%	291
Hanford	GWF Power Systems Company, Inc	Kings	27	Petroleum Coke, NG, Diesel	SF(1)	0.73	96%	27%	28%	172
Lincoln Facility	Sierra Pacific Industries	Placer	13	Woodwaste	ST(2)	0.42	27%	38%	67%	47
San Antonio Community Hospital	San Antonio Community Hospital	San Bernardino	1.8	NG	IC(1)	0.92	56%	47%	68%	15
Monterey Regional Water Pollution Control Cogen	Monterey Regional WPCA	Monterey	1.7	NG, Diesel, Digester Gas	IC(3)	0.59	81%	35%	41%	9

Data sources: eGRID: eGRID2002 Version 2.01 Plant File (Year 1999 Data) (EPA, 2003a).
NEI (HAPs): 1999 Final National Emission Inventory for Hazardous Air Pollutants Version 3, Summary Files (EPA, 2003b).
NEI (criteria): 1999 Final National Emission Inventory for Criteria Pollutants Version 3, California Point Source Files (EPA, 2004b).

[a] Fuel burned based on SCCs listed for electricity generation, in descending order of proportion of emissions due to combustion of that fuel.

[b] Prime mover types are listed with the number of generators using that technology in parens. GT = gas turbine; IC = internal combustion engine; SF = steam turbine fluidized bed combustion; ST = steam turbine.

[c] The fraction of emissions from a cogeneration plant that is attributable to electricity generation, derived from the ratio of electric output to the sum of electric and steam output (EPA, 2003a).

II.A.2.b Hypothetical DG (< 1 MW) Cases

The technologies typical of those that form the current installed base of small-scale DG (< 1 MW) in California are diesel and NG ICEs and NG turbines. The only technologies that are certified by CARB for sale and installation in California after 2003 are microturbines and fuel cells. While each of these technologies can be operated in a number of different operational modes (e.g., peaking, load-following or baseload), for this assessment, we model them in continuous (baseload) mode for consistency with our treatment of the existing units. [10] Each technology class is modeled as if it were co-located at the site of the existing units. In addition, each is modeled at the city halls of the eleven most populous cities in California. Figure 6 displays the locations of these city halls, labeled by the city name. Table 9 summarizes the background characteristics of each of the five technologies types modeled as hypothetical DG cases. Figure 7 depicts four of the five small-scale DG technologies.

[10] In fact, DG technologies are marketed as useful baseload electricity sources (e.g., Capstone Turbine Corporation, 2003).

Figure 6. Locations of the city halls of the eleven most populous cities in California that form part of the hypothetical DG cases.

Table 9. Characteristics of the small-scale, hypothetical DG technologies.

Technology	Technology Class	Efficiency	Typical Capacity Range
Diesel ICE	Pre-2003	44%	0.03 – 5 MW
NG ICE	Pre-2003	35%	0.05 – 5 MW
NG Turbine	Pre-2003	28%	1 – 500 MW
Microturbine	Post-2003	24%	0.03 – 0.35 MW
Low-Temperature Fuel Cell	Post-2007	36%	0.01 – 2 MW

Data sources: Samuelsen *et al.* , 2003 and Energy Nexus Group, 2002.

Natural Gas Internal Combustion Engine

Microturbine

Diesel Internal Combustion Engine

Fuel Cell

Figure 7. Photographs of four small-scale, hypothetical DG technologies. (Sources: Cummins Power Generation, 2004 (NG ICE); Capstone Turbine Corporation, 2002 (microturbine); Detroit Diesel Corporation, 2003 (diesel ICE); Ballard Power Systems, 2002 (fuel cell).)

II.B Pollutant Selection

The pollutants modeled include one from each of two classes: conserved and decaying. A hazard ranking formed the basis for selection of these pollutants (Heath *et al.*, 2003). The figure of merit was an emission factor divided by a concentration guideline appropriate to the health outcomes of interest. The ratio represents a source-oriented, technology-specific hazard potential associated with the specified pollutant. Three health outcomes were assessed: acute non-cancer; chronic non-cancer; and cancer. A "weight of evidence" method was used to determine which pollutants to model. If a particular pollutant had a higher hazard ranking in, for instance, two of three assessments compared to other pollutants of its class (i.e., conserved or decaying), then we selected that pollutant to model.

Primary emissions of particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$) can be treated as a conserved species in outdoor air on the timescales of transport within 100 km. This pollutant class has one of the highest health risks attributable to electricity generation (Krewitt *et al.*, 1998). [11] It also presented the greatest hazard of conserved pollutants in the assessment by Heath *et al*. (2003).

Formaldehyde (HCHO) had the highest hazard ranking among the hazardous air pollutants evaluated and so was selected to represent the case of a decaying pollutant. This assessment only considers formaldehyde exposures directly attributable to emissions from generating electricity. Emissions of other volatile organic compounds (VOC) from the dominant fuel used in California – natural gas – are too low for secondary formation of formaldehyde due solely to this source to be important; thus, we only consider primary emissions in this assessment. [12] Formaldehyde has also been selected as a hazardous air pollutant of particular concern from natural gas combustion for electricity generation for both reciprocating engines and combustion turbines (EPA, 2004c; EPA, 2004d).

NO_x also posed a relatively high risk in this assessment. However, NO_2 — the pollutant for which there are health standards — is a secondary pollutant and modeling its formation and decay chemistry is complex. At this stage, our model cannot accurately assess human exposure to secondary pollutants such as NO_x because it does not incorporate such necessary features as spatially and time-varying background concentrations of other reactive pollutants. However, considering the nitrogen-containing molecule that is emitted as NO_x as a decaying species might provide the ability to estimate population intake to the sum of many nitrogen-containing species of interest. These nitrogen-containing species include nitric oxide (NO), NO_2, nitric acid (HNO_3), peroxyacetyl nitrate (PAN) and particulate ammonium nitrate (NH_4NO_3). Such an effort could be undertakenin subsequent stages of this line of research.

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[11] The atmospheric lifetime of $PM_{2.5}$ was estimated by Seinfeld and Pandis (1998) as "many days", which is greater than the transport time, assuming constant prevailing winds, from any of the cases we evaluate. Using deposition velocity data from Seinfeld and Pandis (1998) for PM of diameter 0.2-2 μm, we estimate losses over 100 km to be 1-8%. These small loss rates justify treating $PM_{2.5}$ as a conserved pollutant.

[12] There are many other sources of formaldehyde exposure in addition to primary emissions from natural gas combustion, including secondary formation from gaseous precursors and primary emissions from motor vehicles, building materials, consumer products and industrial processes. It has been estimated that greater than 75% of summer, daytime, urban formaldehyde is due to secondary formation (e.g., Friedfeld *et al.*, 2002).

II.C Modeling Tools and Input Data

Sections II.C.1-4 report the various calculation methods, data sources and assumptions used in this study.

II.C.1 Gaussian Plume Model

II.C.1.a Gaussian Plume Model for Conserved Pollutants

We model downwind pollutant concentrations from all electricity generation sources using a standard Gaussian plume model (Turner, 1994). We assume that the electricity generation units operate in a baseload mode; in particular, we assume that they emit pollutants at constant rates. In the conserved pollutant case, for steady releases, the time-average, ground-level concentrations downwind of the source, including reflection from the ground, can be estimated as

$$C(x,y,H_E) = \frac{E}{\pi\sigma_y\sigma_x U_E}\exp\left(-\frac{y^2}{2\sigma_y^2}\right)\exp\left(-\frac{H_E^2}{2\sigma_z^2}\right) \quad (1)$$

where E is the steady-state emission rate of a pollutant from the source (g/s), σ_y and σ_z are dispersion parameters in the transverse and vertical directions (m), respectively, U_E is the wind speed at the effective stack height (m/s), H_E is the effective stack height of the emission source accounting for plume rise (m), and x and y are the downwind and transverse distances from the source (m), respectively. The dispersion parameters are functions of downwind distance and stability class. In this analysis, we use dispersion parameters appropriate to the degree of urbanization and release height of the source in question (see section II.C.1.b). This formula also incorporates the slender plume approximation and reflection from the ground (Seinfeld and Pandis, 1998).

We incorporate one important refinement to the basic Gaussian plume model: reflection of the plume not only from the ground but also from the base of the inversion layer (mixing height). The method of images provides an analytic solution (Nazaroff and Alvarez-Cohen, 2001).

The reduced equation is

$$C = \frac{E}{\pi\sigma_y\sigma_z U_E}\exp\left(-\frac{y^2}{2\sigma_y^2}\right)\left\{\sum_{-n}^{n}\exp\left[-\frac{(2nM - H_E)^2}{2\sigma_z^2}\right]\right\} \quad (2)$$

where M is the mixing height (m) and n is an index for the number of reflections. The number of reflections used for each hour varies; we stop adding reflections after converging on a stable solution (defined as less than 1% change in intake fraction assessed over the last three reflections; see section II.D.1.a).

There are four important limitations to our use of the standard Gaussian model. First, one must assume that meteorological conditions (e.g., wind speed and direction) remain constant within the transport time of the plume to use the Gaussian model (Turner, 1994). Travel times for a plume released at Morro Bay or any location in the Los Angeles area, for example, to reach the boundary of our exposed population (100 km) are between 7 and 13 hours at annual-average wind speeds in the prevailing wind direction. Clearly, meteorological conditions do not remain constant over intervals of order 10 h. However, what we seek in this study is closely related to the long-term temporally and spatially averaged ground-level concentration over the entire impact area of the plume. As the system is linear for the pollutants considered here, the assumption of steady state as a means to estimate an average is reasonable.

The second limitation involves the discetization of atmospheric stability into six (Pasquill) classes. This treatment does not fully capture the continuous nature of atmospheric conditions. However, as there are no other descriptions of atmospheric conditions as widely used and trusted as the Pasquill system, we deem its use here appropriate.

Third, while not strictly necessary in the use of the Gaussian model, a common assumption is no loss of pollutant to the ground surface or through the inversion layer, i.e., that there is perfect reflection from those boundaries. While the assumption of perfect reflection at the ground surface may not be strictly true for $PM_{2.5}$, we estimate that this assumption introduces an error of less than 10% over the travel distance of the plume. Thus, $PM_{2.5}$ can be approximated as a conserved pollutant over the distances within the scope of this study.

As for pollutant loss at the upper boundary, for all cases where the effective stack height of a plant is lower than the mixing height, we assume that the bottom of the inversion layer is perfectly reflecting. However, there are many hours of the year when the mixing height is lower than the effective stack height (the proportion is higher for plants with taller stacks). When considering population intake during those hours, we made the simplifying assumption that this condition was completely protective of public health, i.e., that the vertical plume from the stack has enough momentum to fully pass through the inversion base and be separated from the people below. The method of partial plume penetration (Turner, 1994) is an alternative approach that could be used in future work to test the sensitivity of our assumption. We report the number of hours the effective stack height of the plume is higher than the mixing height in section II.C.4.a.

Finally, there are several issues related to the estimation of exposures at the near-source (< 100 m) and 100 km boundaries of our modeling domain. The Gaussian model is not accurate at predicting concentrations within 100 m of the source (Turner, 1994). Large electricity generation units have substantial effective stack heights, leading to sufficiently small concentrations within 100 m to make an insignificant contribution to the population exposure. [13] The hypothetical DG units cause substantially higher concentrations within 100 m owing to their negligible buoyancy- and momentum-induced plume rise. Lai *et al.* (2000) bounded the possible error to intake fraction estimation within the first 100 m downwind and showed that not considering the first 100 m resulted in less than 1% error. Their result was based on an assumption of uniform population

[13] Section II.C.4.b discusses the calculation of effective stack height for both existing units and hypothetical DG cases.

density within the modeling domain. At most, we estimate the population densities in our cases could be ten times higher in the region within 100 m compared to the rest of the modeling domain, so we would expect 10% or less error if we excluded this region entirely. In fact, we estimate concentration within 100 m by extrapolating from a point beyond 100 m to the origin. Thus, we expect our error to be less than 10% owing to this factor.

We limit our assessment of downwind concentration to an outer boundary of 100 km for three reasons. First, standard warnings advise against application of the Gaussian model past 100 km (Turner, 1994). Second, a similar assessment by Marshall *et al.* (2003) found that the contribution to population intake beyond this distance is minor because of the low concentrations achieved after so much dilution. [14] This result is especially true for decaying species. Third, proper treatment of long-range transport would require the application of trajectory-tracking models with appropriate meteorological data, an approach that would require resources beyond those available for this study.

We also explored whether to restrain our assessment to within shorter distances. The Gaussian model has been routinely used for assessments of risk out to 100 km. However, at distances greater than ~20 km from a source, the dispersion parameters on which the Gaussian model is based do not have strong empirical foundation. Various formulations of the dispersion parameters have been validated at the scales of 1 and 10 km (e.g., urban neighborhood- and city-scale) for ground-based and elevated sources in urban and rural areas (Britter and Hanna, 2003; Gifford, 1976; Pasquill, 1961). Many researchers have also demonstrated the validity of the Gaussian model in estimating long-term, temporally- and spatially-averaged ground-level concentrations over short to medium distances (order ~1 - 10 km) in both urban and rural environments (Britter and Hanna, 2003; Hanna *et al.,* 2003; Tsuang, 2003). At greater distances, validations of plume spread by the dispersion parameters or pollutant concentrations by Gaussian models are lacking. Nevertheless, a comparison of central stations to DG limited to distances ~10 km downwind would be substantially biased by not accounting for more distant population exposure. In future refinements of this research, one could highlight the portion of total population intake attributable to distances greater than ~20 km in order to better inform the reader where the results are more uncertain.

Gaussian Dispersion Parameters by Release Type and Urban/Rural Location Category

Observations of the vertical and horizontal spread of a plume released by a point source have been made under various release conditions. Mathematical formulations that describe each set of observations have been proposed. These formulations are often referred to as Gaussian dispersion parameters, or "sigma curves" (named for their mathematical representation as σ_z and σ_y), because they are regularly used in Gaussian plume models to describe how the standard deviation of the concentration distribution of

[14] We note, however, that the work of Marshall, *et al.* (2003) focused on ground-based releases in the South Coast Air Basin. Significant contributions to intake fraction could occur for remote releases that impact heavily populated regions far downwind. However, this situation would not commonly occur for release locations within California.

a plume grows in horizontal and vertical extent depending on various characteristics of the atmosphere. Three reviews of the formulations have recommended that modelers use parameters appropriate to the elevation of the source and roughness of the site (Gifford, 1976; AMS, 1977; Seinfeld and Pandis, 1998). Taking their advice, we have chosen four sets of dispersion parameters to describe the differences in release conditions along two dimensions: whether the source is elevated or near ground-level at the point of release and whether the source is located in an urban or rural area, which affects its characteristic roughness. The next three paragraphs detail the dispersion parameters used under each of these circumstances.

Rural, Ground-level Releases A seminal paper by Pasquill (1961) related the spread of a plume to the standard deviation of the wind direction. His work was based on empirical observations of concentrations resulting from the release of a non-buoyant tracer from a ground-level source over flat, smooth ground. The observations were connected to atmospheric stability in six discrete categories, now known as the Pasquill stability classes. Gifford (1961) then converted the results into families of curves of the standard deviation of pollutant concentration (σ_z and σ_y) for each of the stability classes, A through F. The resulting curves are known as the Pasquill-Gifford curves, to which many authors have fit mathematical formulations. While strictly relevant only to release and topographical conditions similar to those of the experiment (Project Prairie Grass), curves based on this dataset are the most widely recognized and utilized in air dispersion modeling. In this study, we use a fit employing the modified power law form $\sigma = ax^{b+clnx}$, where a, b, and c are empirical parameters that are based on the original Pasquill-Gifford parameters as modified by Davidson (1990). These are the dispersion parameters used for any source in a rural area whose height of release is near ground-level.

Rural, Elevated Releases Briggs (1974) proposed a series of interpolation formulas for σ_y and σ_z dispersion parameters intended for elevated releases. These formulas adhere to the Pasquill-Gifford curves at short distances (when σ_z approaches 50-100 m) (Gifford, 1961), the Brookhaven National Laboratory (BNL) curves at mid- to long-ranges (when σ_z approached 300 m) (Singer and Smith, 1966), and the Tennessee Valley Authority (TVA) curves at very long ranges ($\sigma_z > 300$ m) (Carpenter et al., 1971). The BNL data reflects release of a passive tracer from a 108 m stack at distances of several kilometers. The TVA collected concentration measurements of buoyant gas (SO_2) emissions from ~10 different tall stacks (150 – 750+ m effective stack heights) at distances of up to 30 km from the source. We apply the Briggs interpolation curves to cases of elevated stacks in rural areas.

Urban releases: Ground-level and Elevated Releases Two reviews (AMS, 1977; Hanna et al., 1987) and one recent paper (Hanna et al., 2003) have selected the Briggs urban dispersion parameters as the most appropriate for Gaussian plume modeling in urban areas (Briggs, 1974, as reprinted in Turner, 1994, and Gifford, 1975). Based on analyses of recent urban dispersion experiments in Los Angeles and Salt Lake City (Allwine et al., 2002; Hanna et al., 2003), Hanna et al. (2003) modified these standard parameters to account for the large initial mixing of plumes behind urban canopy

obstacles when released from small sources. [15] This modification leads to an initial plume half-height of $\sigma_{z0} = H_b/2$, where H_b is the average height of buildings in the vicinity of the release point and is valid for release heights less than H_b. Thus, sources with physical stack heights less than H_b have σ_z enhanced, while elevated sources do not. For sources within the urban canopy (i.e., ground-level), the final form of σ_z is given in Table 10, where x is the distance downwind (m). For sources that release above the urban canopy, the same formulas are used, except the σ_{z0} term is not added. The designation of whether a source is modeled as elevated or ground-level is discussed in section II.C.4.a.

Limit on σ_z There is disagreement in the literature as to what cap to place on the value of σ_z. Some argue that the plume thickness should not be allowed to exceed the mixing height (AMS, 1977; Gifford, 1976) while others allow σ_z to mathematically extend beyond the physical limit of the inversion layer (Pasquill, 1961; EPA, 1995). We are persuaded by the former arguments, capping σ_z at the height of the mixing height. Note that while alternative limits do not significantly alter the final intake fraction results, they do change the number of reflections that are required to meet our convergence test. [16]

II.C.1.b Gaussian Plume Model for Decaying Pollutants

The Gaussian plume model can easily incorporate first-order decay of primary pollutants by incorporating an exponential decay term in the expression. Thus, eq 2 is modified

$$C_d = C_c \exp\left(-kx/U_E\right) \tag{3}$$

where C_d is the concentration of the decaying species (g/m^3), C_c is the concentration of a conserved species emitted at the same rate and under the same conditions as the decaying species (g/m^3), k is the decay constant (s^{-1}), U_E is the wind speed at the effective stack height (m/s) and x is the downwind distance (m). If there are multiple loss mechanisms (such as for formaldehyde), the decay constant represents the sum of the rate constants of all applicable loss mechanisms (assumed to be first-order). Similar to our assumption for the conserved pollutant $PM_{2.5}$, we also assume no loss of formaldehyde to the ground surface. While its deposition velocity is higher than for $PM_{2.5}$, leading to losses of approximately 30% over the travel distance of the plume (using data from Christensen *et al.*, 2000), we leave the incorporation of this additional loss factor to future refinements of this line of research.

[15] A second modification to account for the large turbulence intensities during light wind conditions is not used here because it only impacts σ_y. We estimate intake fraction by integrating σ_y analytically with infinite limits in the transverse direction, removing this parameter from explicit consideration.

[16] We tested the impact of changing the limit on σ_z to five and ten times the mixing height. While the number of reflections to reach convergence and the contribution of each reflection to the total intake fraction differed substantially amongst the various caps, the total intake fraction value remained stable.

Table 10. Dispersion parameters for urban point sources emitting within the urban canopy.

Pasquill Type	Stability Class Name	σ_z (m)
A-B	Unstable	$\sigma_{z0} + 0.24x\left(1 + 0.001x\right)^{0.5}$
C	Slightly unstable	$\sigma_{z0} + 0.20x$
D	Neutral	$\sigma_{z0} + 0.14x\left(1 + 0.0003x\right)^{-0.5}$
E-F	Stable	$\sigma_{z0} + 0.08x\left(1 + 0.0015x\right)^{-0.5}$

II.C.2 Meteorological Parameters

Several meteorological parameters are used in the Gaussian plume model: mixing height, wind speed and direction, and stability class. Standard regulatory practice selects an individual year or set of years judged to represent the meteorological conditions leading to a worst-case scenario of pollutant concentrations and/or risk to potentially exposed individuals. While this approach may be useful in regulatory permitting of specific sources, it does not provide a realistic estimate of population exposure under conditions more typically encountered. With the goal of assessing impacts on population exposure from broad changes in electricity generation technologies in mind, we have developed a set of meteorological parameters that are statistically judged typical of the long-term observation record. Our method allows us to generalize the results beyond a dependency on conditions of any particular year or worst-case scenario.

Typical meteorological year (TMY) datasets already exist for solar radiation and surface meteorological elements. The National Renewable Energy Laboratory (NREL) has published a dataset called the Typical Meteorological Year 2 (TMY2) (NREL, 1995), which provides an annual cycle of hourly TMY data for most stations that belong to the National Oceanic and Atmospheric Administration's Solar and Meteorological Surface Observation Network (SAMSON), including ten in California. The TMY2 dataset consists of months selected from individual years (month/year pairs) that have been judged typical of the long-term record, then concatenated to form a complete annual cycle. The TMY2's data are derived from the 1961-1990 National Solar Radiation Data Base and "represent conditions judged to be typical over a long period of time, such as 30 years" (NREL, 1995). The original purpose of the TMY2 dataset was to provide a standard for hourly solar radiation and meteorological data used in energy modeling. The method used in the selection of typical months is also consistent with the objectives and methods of Gaussian plume air dispersion modeling.

Nevertheless, existing TMYs have only provided surface meteorological parameters, whereas mixing heights are also necessary in air dispersion modeling. Thus, borrowing from the concept and methods developed by NREL, we have constructed a Typical Mixing Height Year (TMHY) for the nine surface stations in California and one in Oregon most closely related to the cases we model. Since mixing heights are calculated from upper air and surface observations, this method implicitly returns a file that also includes the surface data that produced the typical mixing heights.

The following sections describe the data sources and methods we used to develop the typical mixing height years and associated surface meteorological parameters.

II.C.2.a Mixing Height

Mixing heights define the upper boundary of the mixing zone for pollutants emitted within that zone. They can be calculated from the vertical profile of pressure and temperature (from radiosonde measurements), hourly surface temperatures, local times of sunset and sunrise, and hourly estimates of atmospheric stability (EPA, 1998; EPA, 1999). In our assessment, these data come from two sources:

1. Measured or modeled solar radiation and surface meteorological data for the period 1961-1990 from SAMSON (NCDC, 1993).
2. Radiosonde (upper air) data for the period 1946-1996 from the National Climatic Data Center of the National Oceanic and Atmospheric Administration (FSL/NCDC, 1997).

The process of calculating hourly mixing heights proceeds in two steps. First, the surface and radiosonde data are input to EPA's Mixing Height Program, which produces twice-daily mixing heights (morning and afternoon) for rural and urban areas. Cities have been observed to exhibit elevated mixing heights in the mornings compared to rural areas due to the urban height island effect (e.g., DeMarrias, 1961). Since routine meteorological observations are typically made outside of cities, adjustments need to be made when modeling air quality in urban areas to account for the known differences. EPA's Mixing Height Program is based on the work of Holzworth (1967), who provides a method for making such adjustments. Holzworth's method has become standard practice in determining twice-daily mixing heights without site-specific meteorological measurements, especially in urban areas.

Holzworth also developed a method for interpolating the twice-daily mixing heights to hourly values, again, for both rural and urban areas (Holzworth, 1972). This is the method used in EPA's meteorological pre-processor, PCRAMMET (EPA, 1999). [17] Required inputs include the twice-daily mixing heights, the hourly surface data, and the latitude and longitude of the observation station, from which local times of sunrise and sunset can be determined. Atmospheric stability is determined within PCRAMMET from the surface data and used in the interpolation scheme. The determination of hourly mixing heights for urban and rural areas uses a slightly different interpolation scheme (EPA, 1999).

We use the urban and rural hourly mixing heights as computed by PCRAMMET with one modification: we reset any mixing heights less than 10 m to 10 m. This is in keeping with EPA guidance (EPA, 2000b). Especially in urban areas where mean building heights are higher than 10 m, a mixing height lower than this is not plausible. Since the choice of a single estimate of minimum acceptable mixing height is essentially arbitrary, tests of the sensitivity of the results to this assumption should be incorporated in future refinements.

The surface and radiosonde datasets come from independent observation networks, as can be seen in Figure 8. To produce a realistic mixing height profile necessitates that both sets correspond spatially and temporally. That is, to produce a mixing height record that is representative of the conditions of a particular region, surface and radiosonde data should both come from that region. In addition, these data should correspond in time. Owing to the limited availability and quality of radiosonde data in certain regions of California, considerable attention was paid to determining which spatial and temporal pairs of surface and radiosonde data met our data quality standards and were candidates in the assessment of which was most typical. The difficulties encountered, method developed and results achieved are described in more detail in Appendix A.

[17] PCRAMMET is the standard regulatory meteorological preprocessor used in conjunction with regulatory air dispersion models such as the Industrial Source Complex (ISC).

Where possible, we used NREL's TMY2 selection for which year of a particular month was most typical. This was our preferred method because mixing heights are a function of surface data, which were already deemed typical. NREL's determination was based on a weighting scheme intended for building energy use calculations (NREL, 1995), but the parameter weightings are not inconsistent with one oriented towards air quality modeling. However, for roughly half of the California SAMSON stations, this method could not be used due to one or more of the following reasons: 1) lack of available radiosonde data from the same time period that met our data quality requirements; 2) input file errors; or 3) meteorological incompatibilities between the surface and radiosonde data. For these cases, we used an empirical method of selecting which spatial and temporal pair of input data produced the most typical twice-daily mixing height profile.

The empirical method is analogous to the Sandia method used to develop the TMY2 data (NREL, 1995). The method involves developing a cumulative distribution function (CDF) of twice-daily mixing heights for all candidate months and statistically determining which month is most typical of the long-term record. The monthly surface data and twice-daily mixing heights for the pairing judged most typical were then input to PCRAMMET to interpolate hourly rural and urban mixing heights. Finally, the hourly results for each typical month were concatenated to form the annual cycle for each surface station in California.

The stations where month/year pairings correspond to those selected in the TMY2 dataset are Long Beach, Los Angeles, Medford OR, Sacramento, San Diego, and San Francisco. The stations where month/year pairings for at least one month were empirically determined are Arcata, Bakersfield, Fresno, and Santa Maria. For Arcata, there were no radiosonde stations within a region encompassing similar meteorological conditions. Instead of discarding this site, we produced two TMHY records using the two closest radiosonde stations (Oakland and Medford, OR). Application of both TMHY records to our study provides an opportunity to test the sensitivity of model output to meteorological inputs.

Several figures display the TMHYs for two stations – San Diego and Bakersfield. Similar results are noted for the other stations for which we produced TMHYs. Figures 9 and 10 show the annual cycle of monthly distributions of urban and rural mixing heights, and Figures 11 and 12 show the daily cycle of hourly distributions of urban and rural mixing heights in the month of August for San Diego and Bakersfield, respectively. These stations provide an interesting contrast. Comparing the plots of the annual cycles, San Diego, a coastal city, has relatively consistent median mixing heights throughout the year, with the highest mixing heights during the swing seasons. By contrast, the mixing heights in Bakersfield, an inland, southern Central Valley city, build toward an annual maximum of both the median and upper range in the summer due to intense summer heating. On the other hand, they both show the same relationship between the urban and rural mixing heights, where the minimum values are higher for urban areas (owing to the nocturnal urban heat island effect) and the range of mixing height is greater for rural areas (owing to wider diurnal temperature fluctuations).

Comparing the plots of the diurnal cycle for August, we see a similar pattern in each city, of higher mixing heights in urban areas in the early morning hours (again, reflecting the nocturnal urban heat island effect) and rural mixing heights showing much

wider variability throughout the day. However, note the scale for each plot: the Bakersfield mixing heights are substantially higher than for San Diego due to much higher temperatures in California's Central Valley than at the coast in the summer.

Raw input files, logs of data modifications (such as filling missing values), logs generated by the two mixing height programs and all output files are available from the authors upon request. We plan to post the final TMHY data files and our manual of procedures (Appendix A) on a publicly accessible website in the near future.

II.C.2.b Wind Speed and Direction

Since surface meteorological data are inputs to the calculation of mixing heights, the SAMSON data corresponding to the set of month/year pairings selected as typical of mixing heights form part of the typical meteorological year for each surface station. Where mixing height data were available, we selected the same set of month/year pairs as in NREL's TMY2s (NREL, 1995). In other cases, we use the month/year pairs selected by our empirical method of developing the TMHY.

Wind speed is used directly in the Gaussian plume equation, while wind direction determines the direction of downwind exposed population. Wind directions are reported in the SAMSON dataset in ten degrees bins. To compensate for bias introduced by the binning, PCRAMMET adds a random flow vector between -4 and 5 to the input wind direction, which produces wind directions in integer degrees (EPA, 1999). To improve computational efficiency, we re-grouped the directions into three-degree bins before modeling. While this introduces some inaccuracy in our results, we do not expect any bias from the binning.

Wind speeds are reported in tenths of meters per second and are used unaltered from the original SAMSON dataset. Calms are reported in this dataset as zero wind speed. Because wind speed appears in the denominator of the Gaussian equation, calms cannot be directly evaluated in a Gaussian model. Near-source concentrations increase monotonically with decreasing wind speed, such that periods of calm conditions could present a significant health risk for local exposure to air emissions, especially from ground-source releases. By neglecting calms, we expect to underpredict the true population exposure. Table 11 reports the proportion of calm hours for each meteorological station used in our modeling.

Figure 8. Map of surface and radiosonde stations from whose data the typical mixing height years were created.

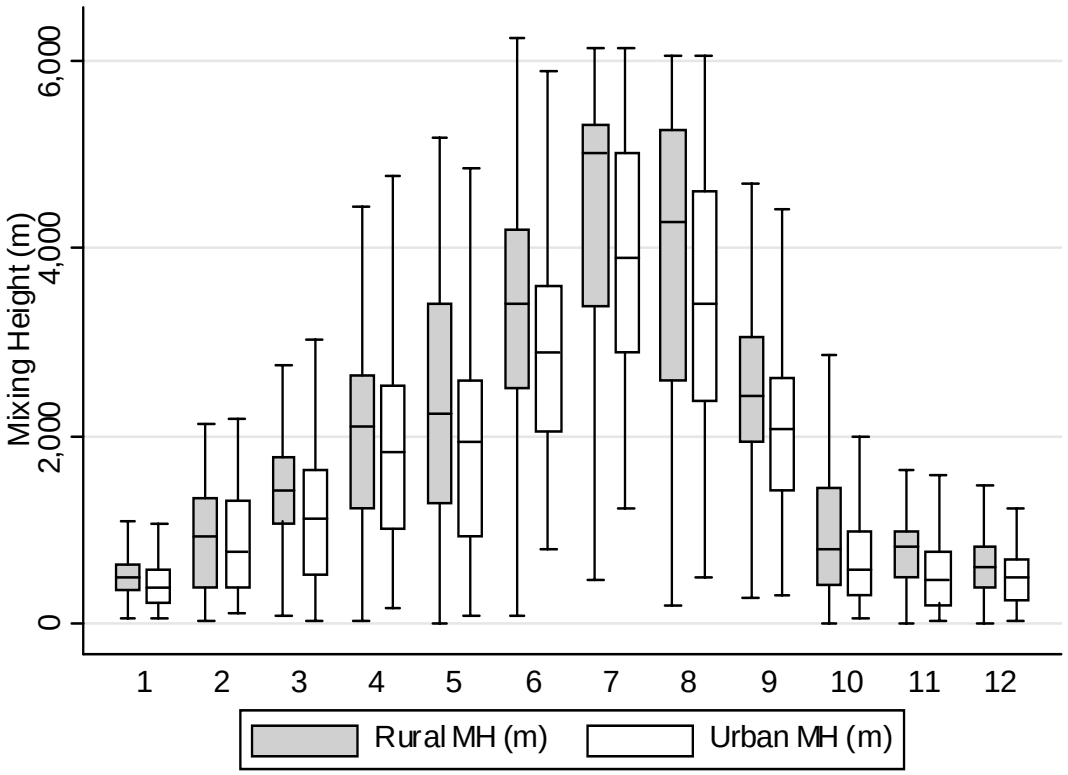

Figure 9. Annual cycle of monthly distributions of Bakersfield urban and rural typical mixing heights (MH). The interquartile box displays the median (center line), 25th and 75th percentile values (bottom and top of the box, respectively). The difference between the 25th and 75th percentile values is the interquartile range. The barred end of the line extending from the top of the box represents the largest data point that is less than or equal to the 75th percentile plus 1.5 times the interquartile range; the barred end of the line extending from the bottom of the box is constructed in an analogous but opposite manner. Any observations beyond this range are shown as points above or below those lines and are statistically considered "outside values."

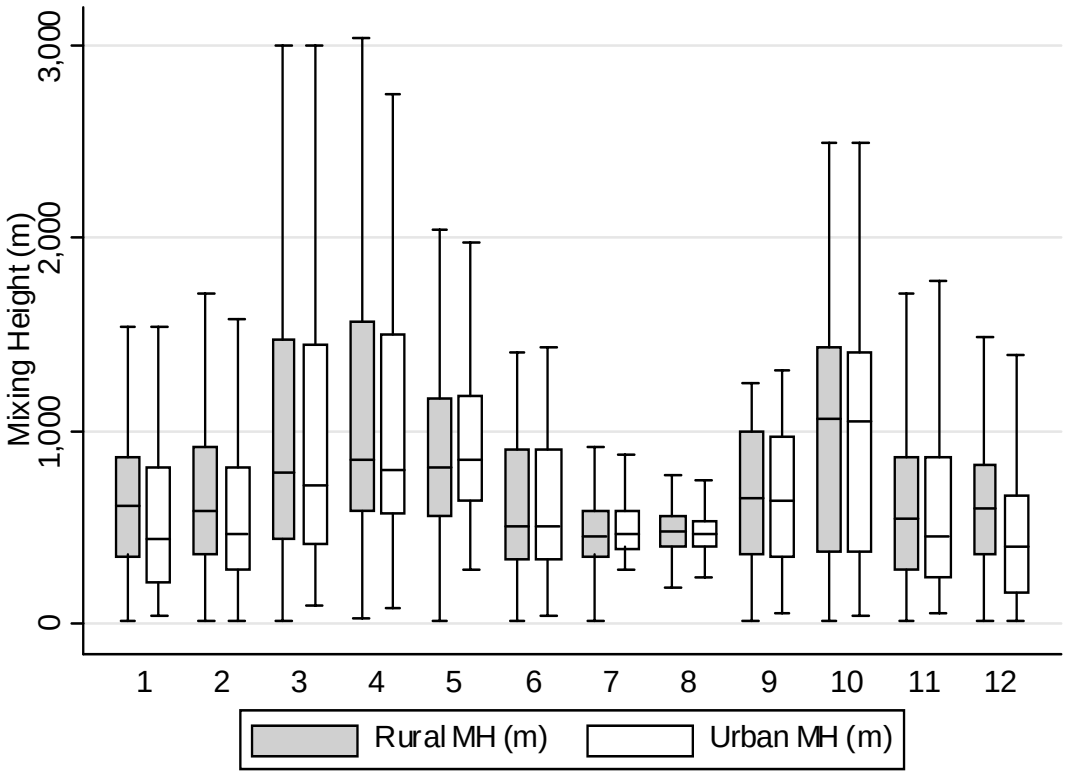

Figure 10. Annual cycle of monthly distributions of San Diego urban and rural typical mixing heights (MH). (See Figure 9 caption for interpretation of the interquartile box plot.)

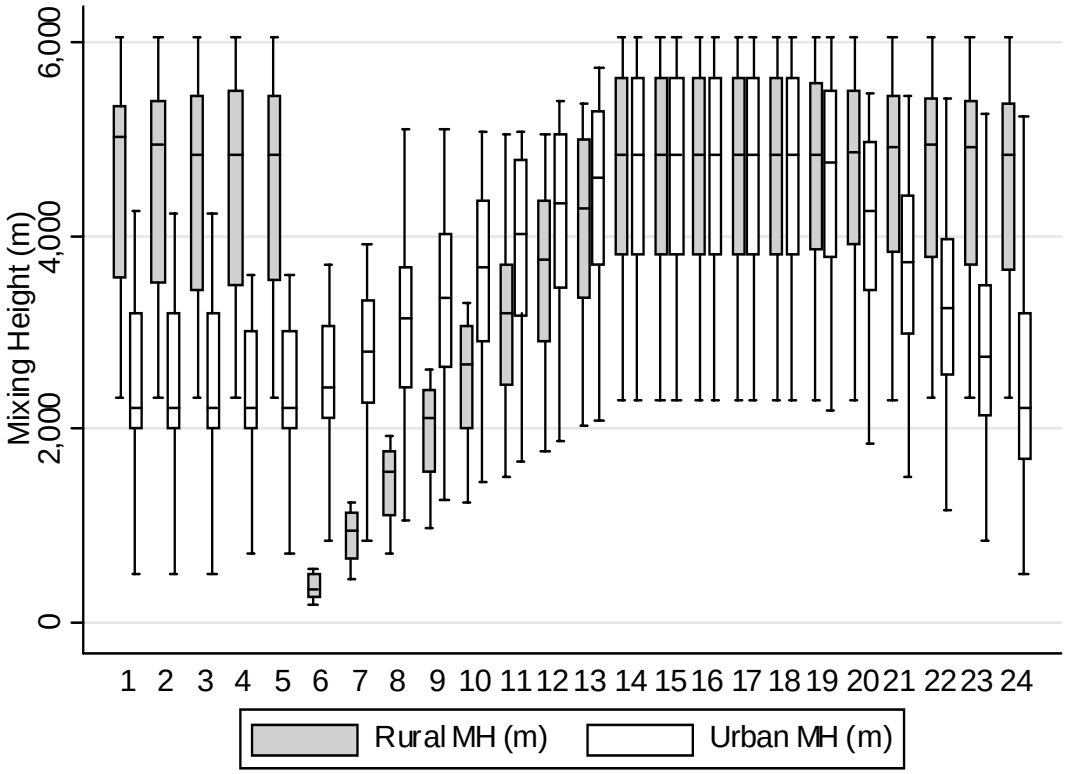

Figure 11. Daily cycle of hourly distributions of urban and rural typical mixing heights (MH) for Bakersfield for the month of August. (See Figure 9 caption for interpretation of the interquartile box plot.)

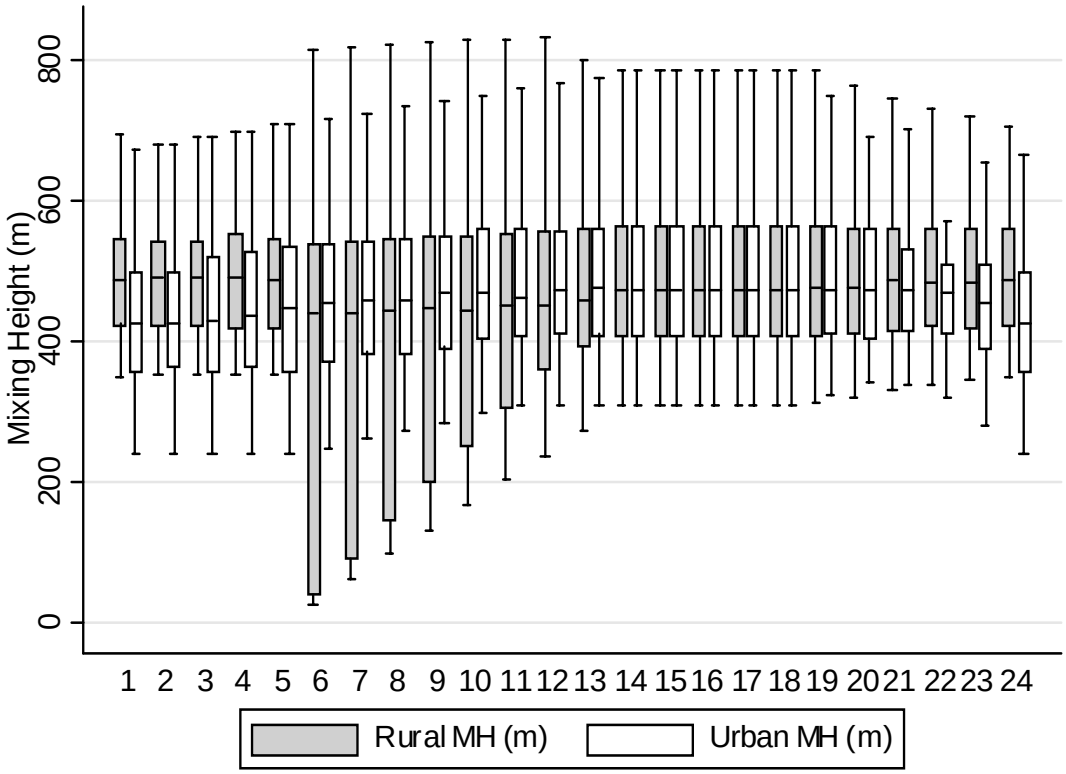

Figure 12. Daily cycle of hourly distributions of urban and rural typical mixing heights (MH) for San Diego for the month of August. (See Figure 9 caption for information about how to interpret the interquartile box plot.

Table 11. Annual prevalence of calms for each surface meteorological station.

Surface Meteorological Station	Annual Prevalence of Calms
Arcata	14%
Bakersfield	9%
Fresno	9%
Los Angeles	4%
Long Beach	11%
Sacramento	14%
San Diego	6%
San Francisco	5%
Santa Maria	4%

II.C.2.c Atmospheric Stability Class

Atmospheric stability is determined by the meteorological pre-processor, PCRAMMET, which we use to calculate mixing height. PCRAMMET uses Turner's objective method based on surface observations of wind speed, cloud cover and ceiling, as well as time of day (Turner, 1964). This is the standard method used in air dispersion modeling to determine Pasquill-Gifford stability classes.

Stability classes appropriate for urban areas are modified from the standard output, which are applicable to rural areas. In urban areas, stability classes 5, 6, and 7 (Pasquill E, F and G) are treated as 4 (Pasquill D, or neutral) based on evidence that urban areas are typically neutral stability and never stable due to the urban heat island effect (Turner, 1964). This convention of converting what otherwise would be assessed as stable conditions into neutral has been supported in recent research as well (Venkatram *et al.*, 2002; Hanna *et al.*, 2003).

II.C.3 Population Parameters

To assess population inhalation intake of air pollutants, there are two important factors related to the exposed population: the number and spatial distribution of exposed people and their breathing rate. Population density is heterogeneous, varying in both space and time. Census tract-level population density was utilized to capture spatial variability. Shoreline-clipped, year 2000 census tracts (in an Albers Equal Area projection, North American Datum, 1983) were obtained from ESRI (2004) for processing in ArcMap 8.3 (ESRI, 2002). Demographic information, including population density, is included in the dataset. We did not consider temporal variability in population density for this assessment.

Because some cases are located within 100 km of the Mexican border, we integrated the most recent and spatially refined demographic maps available for Mexico into our analysis (CIESIN, 2004). These maps, provided in a geographic projection, Clarke 1866 datum, were converted to the same projection and datum as the census data and spatially joined to the map of California. The spatial resolution of these maps is to the municipality level, which is roughly equivalent to a US county. The smallest political entity in Mexico is the locality (equivalent to a US city or town), but we could find no maps for localities. This mismatch in spatial resolution between the US and Mexico likely results in an underestimate of total population intake for sources close to the Mexican border. The areas of highest population density in the adjacent Mexican municipalities are located just south of the border where concentrations and exposures are expected to be higher. In addition, the year 2000 Mexican census reveals that the population, especially in border cities such as Tijuana, has grown substantially (INEGI, 2004). It appears that the municipality boundaries have changed between 1990 and 2000 as well. We were not able to obtain maps of the year 2000 boundaries.

The locations of all of our cases were placed on the map according to their NEI coordinates as shown in Figures 3 - 6. Radiating lines representing wind direction were added to each location at 3° intervals, starting at N 3° E and extending a length of 100

km. These radiating lines were converted to points designating where population density information was required for the model integration. The points were evenly spaced at 0.5 km intervals to match the numerical integration scheme of the intake fraction calculation (see section II.D.2.a). The demographic data associated with the census tracts were then spatially joined to the points, and exported as a database for use in the exposure assessment.

Breathing rates are also heterogeneous, varying by age, gender, level of activity, and health status. We assume a constant breathing rate equal to the estimated lifetime population-average value of 12 m^3/d (Layton, 1993). In this regard, our assessment differs from typical risk assessments that use the substantially higher adult, male breathing rate, 20 m^3/d, as a conservative assumption.

II.C.4 Modeling Designations and Data Inputs for Existing Units and Hypothetical DG Cases

This section first describes the three designations required for modeling each of our cases – urban/rural location category, elevated/ground-based release type and closest meteorological station. It then reports the values used for two important model inputs – effective stack height and emission factors – as well as the data sources, assumptions and method used to determine those values.

II.C.4.a Modeling Designations

There are three designations required in our Gaussian plume model. First, we must specify whether the location of the source in question is an urban or rural area. Second, each source is designated either as elevated, ground-based depending on its physical stack height and whether it is in an urban or rural area. Finally, in order to use the most appropriate meteorological conditions, we must select the closest appropriate meteorological station.

The urban/rural designation affects the selection of 1) the dispersion parameters; 2) the mixing height; 3) the stability class; 4) the parameters used to adjust wind speed to the height of the physical stack (for calculation of effective stack height) and to the effective stack height (for the intake fraction calculation); and 5) the formaldehyde decay rate. The physical reasoning why the urban/rural designation affects the first four parameters is due to the difference in characteristic roughness length (urban areas have more densely spaced and taller structures leading to greater roughness lengths (Stull, 1988)) as well as difference in vertical boundary layer heat flux (urban areas have greater heat flux owing to both increased human activity and the urban heat island effect). The formaldehyde decay rate is affected owing to its dependence on the background concentration of a radical related to urban air pollution (the hydroxyl radical). The first three factors that the urban/rural designation affects were discussed in sections II.C.1.b, II.C.2.a and II.C.2.c, respectively; the fourth is discussed in the next section and the fifth will be discussed in section II.C.5.

The US Census designates Urbanized Areas (UA) as areas encompassing at least 50,000 people using criteria based on population density (US Census, 2002). [18] For the purposes of air dispersion modeling, we designate a source location as "urban" if it is in or within 500 m of an UA, determined by plotting all cases in ArcMap 8.3 on UA Census TIGER/Line maps (ESRI, 2004). An exception to this rule is made when a source location is judged significantly isolated from other population centers such that for air dispersion modeling purposes a rural designation is more appropriate. Two cases of this sort arose: Salinas landfill (existing DG (> 1 MW)) located at the outskirts of the Salinas UA, and Coachella (central station) located at the outskirts of the Indio-Cathedral City-Palm Springs UA. Both exceptions are for sources that are located on the edge of UAs in otherwise rural areas.

The elevated/ground-based designation affects the selection of the dispersion parameters. We distinguish the threshold for this designation between rural and urban sources in keeping with the experimental basis of each set of dispersion parameters. The rural, ground-based dispersion parameters are based on releases of a non-buoyant tracer at near ground level (Pasquill, 1961). The experimental conditions on which the Briggs interpolation formulas for rural, elevated releases were based included releases of non-buoyant tracers at 108 m (Singer and Smith, 1966) and buoyant gases at effective stack heights (including plume rise) of 150-750+ m (Carpenter *et al.*, 1971). Thus, a judgment is required for all sources emitting between ground-level and 108 m. We use 50 m as the demarcation line: elevated sources are those that that emit above 50 m whereas ground-based sources are those that emit below 50 m. In future refinements of this research, one could test the sensitivity of the results to the selection of which set of dispersion parameter formulas is used for those cases emitting at a height between 108 m and ground-level.

To our knowledge, there have been no dispersion experiments conducted on urban, elevated sources. However, based on the work of Hanna *et al.* (2003), we can account for whether the emission occurs below or above the mean building height. [19] Mean building heights (H_b) for various urban areas across North America have been calculated and summarized by Grimmond and Oke (1999). H_b ranges from 4.7 m in suburban residential areas to 34.3 m in central cities. Since site-specific values are not available for nearly all of our cases, a typical value of 10 m is used. Thus, ground-level, urban sources are distinguished by physical stack heights less than or equal to 10 m (i.e., all hypothetical DG technologies and some cogeneration and existing DG (> 1 MW) sources); elevated, urban sources are those with physical stack heights above 10 m. Since this is an arbitrary demarcation, future work should test the sensitivity of the within/above-canopy designation for those sources with physical stack heights between 5 and 35 m, the range of H_b found by Grimmond and Oke (1999).

Finally, since we have meteorological parameters from ten locations in California and Oregon, we had to select which meteorological station was most closely related to

[18] For the year 2000 census, the US Census Bureau introduced Urban Clusters (UC), which are similar to Urbanized Areas but with a lower total population threshold (2,500-50,000 people). However, UCs do not meet our definition of an urban area for air dispersion modeling purposes.

[19] Hanna *et al.* (2003) found that for ground-level sources released in Los Angeles and Salt Lake City, the plume dispersed rapidly to the height of the surrounding buildings. A term was added to the dispersion parameters used in their baseline, urban air dispersion model to account for this effect (σ_{zo}).

the conditions at that site. Characteristics considered included belonging to the same air basin, proximity, and sharing similar proximity to the coast.

A summary of the modeling designations used for existing units is presented in Tables 12 – 14, along with emissions, emission factors and stack parameters. Table 15 summarizes the modeling designations associated with the city hall locations for the hypothetical DG cases. Table 16 summarizes the modeling designation for the small-scale, hypothetical DG technologies, as well as the emission factors and stack-related inputs.

Table 12. Modeling designations, emissions, emission factors and stack data for the 25 central station existing units in 1999.

eGRID Name	MODELING DESIGNATIONS		EMISSIONS		EMISSION FACTOR		STACK DATA								
	Urban/ Rural[a]	Closest Met. Station[b]	Primary $PM_{2.5}$ tons/y (1999)	HCHO tons/y (1999)	Primary $PM_{2.5}$ mg/kWh_{del}	HCHO mg/kWh_{del}	Number of Stacks Modeled[c]	Stack Height (m)	Elevated/ Ground-based[d]	Stack Diameter (m)	Exit Gas Velocity (m/s)	Exit Gas Temp. (K)	Emissions Weighting[e]	Annual-Average Effective Stack Height (m)	Proportion of Annual Hours Effective Stack Height > Mixing Height
AES Alamitos	Urban	Long Beach	109	4.2	32	1.2	4	61	Elevated	3.7	21	408	18%	307	15%
								61	Elevated	4.3	25	399	28%	377	20%
								61	Elevated	5.2	26	397	43%	464	25%
								19	Elevated	3.0	19	581	11%	375	20%
Pittsburg Power	Urban	Sacramento	113	2.7	23	0.54	3	65	Elevated	3.5	28	422	16%	286	16%
								137	Elevated	4.2	36	414	29%	387	20%
								137	Elevated	6.1	32	414	55%	502	25%
Ormond Beach Generating Station	Rural	Santa Maria	47	0.78	32	0.53	2	72	Elevated	6.7	14	369	95%	299	18%
								21	Ground-based	1.5	14	477	5%	91	5%
Duke Energy Moss Landing LLC	Rural	Santa Maria	173	12	29	2.0	2	80	Elevated	3.1	14	386	12%	185	10%
								152	Elevated	5.4	35	394	88%	451	29%
AES Redondo Beach LLC	Urban	LA	40	2.4	30	1.8	3	61	Elevated	4.3	34	594	14%	478	38%
								61	Elevated	4.9	52	644	29%	719	55%
								61	Elevated	5.5	76	644	57%	1010	68%
Duke Energy Morro Bay LLC	Rural	Santa Maria	89	0.12	28	0.038	3	137	Elevated	4.5	14	428	24%	303	18%
								137	Elevated	4.3	14	408	22%	286	16%
								137	Elevated	4.3	36	422	54%	399	25%
Etiwanda Generating Station	Urban	Bakersfield	38	0.20	34	0.18	2	54	Elevated	3.7	17	403	31%	231	10%
								61	Elevated	4.3	28	400	69%	333	15%

Table 12. con't

eGRID Name	MODELING DESIGNATIONS		EMISSIONS		EMISSION FACTOR		STACK DATA								
	Urban/ Rural[a]	Closest Met. Station[b]	Primary $PM_{2.5}$ tons/y (1999)	HCHO tons/y (1999)	Primary $PM_{2.5}$ mg/kWh_{del}	HCHO mg/kWh_{del}	Number of Stacks Modeled[c]	Stack Height (m)	Elevated/ Ground-based[d]	Stack Diameter (m)	Exit Gas Velocity (m/s)	Exit Gas Temp. (K)	Emissions Weighting[e]	Annual-Average Effective Stack Height (m)	Proportion of Annual Hours Effective Stack Height > Mixing Height
Encina	Urban	San Diego	93	14	24	3.7	1	122	Elevated	7.9	32	415	100%	647	48%
El Segundo Power	Urban	LA	63	1.5	20	0.48	2	61	Elevated	3.7	20	416	35%	246	17%
								61	Elevated	4.3	28	386	65%	303	22%
Duke Energy South Bay LLC	Urban	San Diego	56	8.6	32	4.8	3	57	Elevated	3.0	20	405	46%	208	11%
								10	Ground-based	2.2	17	531	20%	222	13%
								80	Elevated	3.1	14	386	34%	185	9%
Contra Costa Power	Rural	Sacramento	68	0.36	22	0.12	1	137	Elevated	5.7	41	422	100%	518	23%
Mandalay Generating Station	Urban	Santa Maria	38	1.1	30	0.90	4	19	Elevated	3.0	19	581	10%	354	27%
								77	Elevated	3.1	13	399	7%	204	16%
								14	Elevated	5.2	36	451	59%	874	56%
								61	Elevated	5.2	14	367	24%	290	23%
AES Huntington Beach LLC	Urban	Long Beach	28	0.77	31	0.86	1	62	Elevated	4.9	26	408	100%	452	24%
Valley	Urban	LA	0.01	0.22	0.079	1.7	1	80	Elevated	3.1	14	386	100%	179	10%
Hunters Point	Urban	SF	26	0.18	40	0.27	2	61	Elevated	5.0	12	503	48%	278	20%
								76	Elevated	3.5	26	443	52%	263	18%
Kearny	Urban	San Diego	13	0.60	430	20	1	19	Elevated	3.0	19	581	100%	306	19%
Riverside Canal Power Co	Urban	Bakersfield	0.8	0.00002	39	0.0010	2	21	Elevated	2.5	10	441	42%	141	5%
								30	Elevated	3.1	10	429	58%	165	6%

Table 12. con't

eGRID Name	MODELING DESIGNATIONS		EMISSIONS		EMISSION FACTOR		STACK DATA								
	Urban/ Rural[a]	Closest Met. Station[b]	Primary $PM_{2.5}$ tons/y (1999)	HCHO tons/y (1999)	Primary $PM_{2.5}$ mg/kWh_{del}	HCHO mg/kWh_{del}	Number of Stacks Modeled[c]	Stack Height (m)	Elevated/ Ground-based[d]	Stack Diameter (m)	Exit Gas Velocity (m/s)	Exit Gas Temp. (K)	Emissions Weighting[e]	Annual-Average Effective Stack Height (m)	Proportion of Annual Hours Effective Stack Height > Mixing Height
Duke Energy Oakland LLC	Urban	SF	1.3	0.023	280	4.8	2	21	Elevated	4.4	18	722	50%	420	31%
								21	Elevated	3.9	22	722	50%	411	30%
Mountainview Power Co LLC	Urban	Bakersfield	1.6	0.017	35	0.37	1	40	Elevated	3.1	11	414	100%	165	6%
Humboldt Bay	Rural	Arcata	12	0.067	28	0.16	2	37	Ground-based	3.1	11	439	45%	178	11%
								37	Ground-based	3.1	14	450	55%	203	13%
Redding Power	Rural	Medford	1.0	0.0020	34	0.069	1	17	Ground-based	2.2	20	617	100%	238	8%
Coachella	Rural	Bakersfield	0.8[f]	0.0070	82	0.72	1	10	Ground-based	0.6	23	660	100%	52	1%
Magnolia	Urban	LA	2.6[f]	0.0076	2600	7.7	1	80	Elevated	3.1	14	386	100%	179	10%
Puente Hills Energy Recovery	Urban	Long Beach	3.8	0.0065	10	0.017	1	18	Elevated	2.9	20	620	100%	390	21%
North Island	Urban	San Diego	1.8	0.032	360	6.5	1	10	Ground-based	1.9	43	470	100%	290	18%

Data sources: Emissions: 1999 National Emissions Inventory for Hazardous Air Pollutants (EPA, 2003b) and National Emissions Inventory for Criteria Pollutants (EPA, 2004b).
Emission Factor: Calculated based on emissions and plant efficiency (from eGRID (EPA, 2003a)) as well as an assumed 10% line loss (EIA, 1999).
Stack Data: From one or more of the NEI for HAPs, NEI for criteria pollutants and the 1996 National Emissions Trends (EPA, 1996) except Annual-Average Effective Stack Height which is calculated hourly based on stack parameters and atmospheric conditions.

[a] Urban and rural designations are based on U.S. Census maps of urbanized areas (see section II.C.4.a).

[b] Closest meteorological station is based not only on proximity but also judgement on similarity of meteorological conditions between the plant and nearby surface meteorological stations.

[c] Number of stacks modeled may differ from the true number of stacks since, for modeling efficiency, stacks with nearly identical stack parameters are consolidated to one modeled stack.

[d] The elevated / ground-based designation is based on the physical stack height and whether the plant is in an urban or rural area (see section II.C.4.a).

[e] Emission weighting is determined as the proportion of total volumetric flow (as reported in the Stack Data sources) from the stack in question.

[f] This plant has no reported $PM_{2.5}$ emissions in the NEI for criteria pollutants in 1999. Those listed here are reported in the CARB's 1999 Emissions Inventory, Facility Search (CARB, 2004b).

Table 13. Modeling designations, emissions, emission factors and stack data for the six DG (> 1 MW) existing units in 1999.

eGRID Name	MODELING DESIGNATIONS		EMISSIONS		EMISSION FACTOR		STACK DATA								
	Urban/ Rural[a]	Closest Met. Station[b]	Primary $PM_{2.5}$ tons/y (1999)	HCHO tons/y (1999)	Primary $PM_{2.5}$ mg/kWh_{del}	HCHO mg/kWh_{del}	Number of Stacks Modeled[c]	Stack Height (m)	Elevated/ Ground-based[d]	Stack Diameter (m)	Exit Gas Velocity (m/s)	Exit Gas Temp. (K)	Emissions Weighting[e]	Annual-Average Effective Stack Height (m)	Proportion of Annual Hours Effective Stack Height > Mixing Height
Pebbly Beach	Rural	Long Beach	69	0.076	2400	2.7	2	61	Elevated	3.7	20	416	34%	262	12%
								61	Elevated	4.3	28	386	66%	318	15%
Penrose	Urban	LA	-[f]	0.17	-	2.3	1	8	Ground-based	0.6	22	693	100%	53	2%
Patio Test Solar Turbines Inc	Urban	San Diego	3.3	0.32	210	20	1	21	Elevated	1.3	8	475	100%	63	3%
Olinda Generating Plant	Urban	Long Beach	0.48	0.042	12	1.1	1	8	Ground-based	0.9	26	730	100%	135	7%
Marina Landfill Gas	Rural	Santa Maria	4.0	0.00019	180	0.0084	1	8	Ground-based	0.6	22	693	100%	51	3%
Salinas	Rural	Santa Maria	-[f]	3.9	-	350	1	8	Ground-based	0.6	22	693	100%	51	3%

Data sources: Emissions: 1999 National Emissions Inventory for Hazardous Air Pollutants (EPA, 2003b) and National Emissions Inventory for Criteria Pollutants (EPA, 2004b).
Emission Factor: Calculated based on emissions and plant efficiency (from eGRID (EPA, 2003a)).
Stack Data: From one or more of the NEI for HAPs, NEI for criteria pollutants and the 1996 National Emissions Trends (EPA, 1996) except Annual-Average Effective Stack Height which is calculated hourly based on stack parameters and atmospheric conditions.

[a] Urban and rural designations are based on U.S. Census maps of urbanized areas (see section II.C.4.a).

[b] Closest meteorological station is based not only on proximity but also judgement on similarity of meteorological conditions between the plant and nearby surface meteorological stations.

[c] Number of stacks modeled may differ from the true number of stacks since, for modeling efficiency, stacks with nearly identical stack parameters are consolidated to one modeled stack.

[d] The elevated / ground-based designation is based on the physical stack height and whether the plant is in an urban or rural area (see section II.C.4.a).

[e] Emission weighting is determined as the proportion of total volumetric flow (as reported in the Stack Data sources) from the stack in question.

[f] This plant has no reported $PM_{2.5}$ emissions in the NEI nor the CARB's Emissions Inventory, Facility Search for 1999 (CARB, 2004b).

Table 14. Modeling designations, emissions, emission factors[a] and stack data for the six cogeneration existing units in 1999.

eGRID Name	MODELING DESIGNATIONS		EMISSIONS		EMISSION FACTOR		STACK DATA								
	Urban/ Rural[b]	Closest Met. Station[c]	Primary $PM_{2.5}$ tons/y (1999)	HCHO tons/y (1999)	Primary $PM_{2.5}$ mg/kWh_{del}	HCHO mg/kWh_{del}	Number of Stacks Modeled[d]	Stack Height (m)	Elevated/ Ground-based[e]	Stack Diameter (m)	Exit Gas Velocity (m/s)	Exit Gas Temp. (K)	Emissions Weighting[f]	Annual-Average Effective Stack Height (m)	Proportion of Annual Hours Effective Stack Height > Mixing Height
Live Oak Cogen	Rural	Bakersfield	0.19	0.31	0.40	0.63	1	10	Ground-based	0.6	23	660	100%	52	1%
Mt Poso Cogeneration	Rural	Bakersfield	0.053	0.048	0.14	0.13	1	52	Elevated	3	17	422	100%	183	6%
Hanford	Rural	Fresno	0.20	0.022	1.1	0.11	1	24	Ground-based	1.4	8	439	100%	69	2%
Lincoln Facility	Rural	Sacramento	2.1	1.1	1.9	0.94	2	35	Ground-based	2.2	10	428	67%	108	6%
								17	Ground-based	1.5	10	374	33%	57	3%
San Antonio Community Hospital	Urban	Bakersfield	0.1[g]	0.0061	1.5	0.092	3	21	Elevated	1.3	8	475	59%	63	1%
								10	Ground-based	0.4	10	505	8%	21	0.1%
								10	Ground-based	0.6	23	660	33%	58	1%
Monterey Regional Water Pollution Control Cogen	Urban	Santa Maria	0.010	0.051	0.62	3.2	2	10	Ground-based	0.6	23	660	7%	67	7%
								17	Elevated	2.3	21	615	93%	293	23%

Data sources: Emissions: 1999 National Emissions Inventory for Hazardous Air Pollutants (EPA, 2003b) and National Emissions Inventory for Criteria Pollutants (EPA, 2004b).
Emission Factor: Calculated based on emissions and plant efficiency (from eGRID (EPA, 2003a)) as well as an assumed 10% line loss (EIA, 1999).
Stack Data: From one or more of the NEI for HAPs, NEI for criteria pollutants and the 1996 National Emissions Trends (EPA, 1996) except Annual-Average Effective Stack Height which is calculated hourly based on stack parameters and atmospheric conditions.

[a] These emission factors are not used to estimate IGR since we are not confident that they truly are 10-100x lower than for other existing units.

[b] Urban and rural designations are based on U.S. Census maps of urbanized areas (see section II.C.4.a).

[c] Closest meteorological station is based not only on proximity but also judgement on similarity of meteorological conditions between the plant and nearby surface meteorological stations.

[d] Number of stacks modeled may differ from the true number of stacks since, for modeling efficiency, stacks with nearly identical stack parameters are consolidated to one modeled stack.

[e] The elevated / ground-based designation is based on the physical stack height and whether the plant is in an urban or rural area (see section II.C.4.a).

[f] Emission weighting is determined as the proportion of total volumetric flow (as reported in the Stack Data sources) from the stack in question.

[g] This plant has no reported $PM_{2.5}$ emissions in the NEI for criteria pollutants in 1999. Those listed here are reported in the CARB's 1999 Emissions Inventory, Facility Search (CARB, 2004b).

Table 15. Modeling designations for the eleven city hall locations of hypothetical DG (< 1 MW) cases.

CITY HALL	MODELING DESIGNATIONS	
	Urban/ Rural[a]	Closest Met. Station[b]
Los Angeles	Urban	Los Angeles
San Diego	Urban	San Diego
San Jose	Urban	San Francisco
San Francisco	Urban	San Francisco
Long Beach	Urban	Long Beach
Fresno	Urban	Fresno
Sacramento	Urban	Sacramento
Oakland	Urban	San Francisco
Santa Ana	Urban	Long Beach
Anaheim	Urban	Long Beach
Riverside	Urban	Bakersfield

[a] Urban and rural designations are based on U.S. Census maps of urbanized areas (see section II.C.4.a).

[b] Closest meteorological station is based not only on proximity but also judgement on similarity of meteorological conditions between the city hall and nearby surface meteorological stations.

Table 16. Modeling designations, emission factors and stack data for small-scale, hypothetical DG (< 1 MW) technologies.

Hypothetical DG Technology	Technology Class	MODELING DESIGNATION	EMISSION FACTOR		STACK DATA			
		Elevated / Ground based[a]	Primary $PM_{2.5}$ mg/kWh_{del}	HCHO mg/kWh_{del}	Number of Stacks Modeled[b]	Emissions Weighting[c]	Annual-Average Effective Stack Height (m)	Proportion of Annual Hours Effective Stack Height > Mixing Height
Diesel ICE	Pre-2003	Ground-based	1400	4.2	1	100%	5	0%
NG ICE	Pre-2003	Ground-based	220	91	1	100%	5	0%
NG Turbine	Pre-2003	Ground-based	41	3.9	1	100%	5	0%
Microturbine	Post-2003	Ground-based	38	4.4	1	100%	5	0%
Low-Temperature Fuel Cell	Post-2007	Ground-based	28	-[d]	1	100%	5	0%

Emission Factor Data Sources: for $PM_{2.5}$: Table 2 (pre-2003), Table 7 (post-2003) and Table 8 (post-2007) from Samuelsen *et al. (*2003).
for HCHO: AP-42 (EPA, 2000a) with efficiency from Samuelsen *et al.* (2003).

[a] All hypothetical DG technologies, in all locations, are considered ground-based sources owing to their assumed, constant effective stack height of 5 m.

[b] A single stack is assumed for DG technologies.

[c] Emission weighting is 100% since we assume only one stack.

[d] No emission factor for formaldehyde has been reported in the literature.

II.C.4.b Data Inputs

Number of Stacks, Effective Stack Height and Stack Weightings

When a pollutant is released from a large combustion source, it is usually emitted from a stack with some exit velocity and elevated temperature compared to the ambient conditions. Both of these factors cause the plume to rise above the physical height of the stack before its net effective velocity aligns to that of the prevailing wind. The sum of the physical stack height plus the plume rise, i.e., the "effective stack height," is the release height used in Gaussian plume models. There are multiple methods to calculate plume rise and determine the effective stack height (Seinfeld and Pandis, 1998). For existing units, we use the method outlined in Turner (1994) to calculate hourly values of effective stack height based on constant parameters associated with the physical stack and ambient atmospheric conditions that change hourly. Appendix B details the procedure we employ.

For the small-scale DG-technologies, we use an effective stack height of 5 m, nominally assuming that the emissions occur near ground level and that the plume rise is minimal due to the low volumetric flow and exit velocity. [20] This assumption is partially validated for a popular model of microturbine: the Capstone 60 kW C60. Assuming manufacturer specifications for stack parameters (Capstone Turbine Corporation, 2005), we estimate annual-average effective stack height to be within the range of 2-5 m. A recent study of the air quality impacts of DG in the South Coast Air Basin made a similar assumption of effective stack height of 5 m (Samuelsen *et al.*, 2003).

The stack parameters required in the calculation of effective stack heights include physical stack height, stack diameter at the point of exit, exhaust gas temperature and exit velocity. The most reliable source of these data is the NEI for HAPs, which reports whether the value is measured or a default used to either fill missing values or correct values that are physically implausible (EPA, 2003b). The NEI for criteria pollutants reports stack parameters but not whether the value is original or default (EPA, 2004b). Another source of stack parameters is the 1996 National Emissions Trends (NET), which also does not report whether the values are original or defaults (EPA, 1996).

We screened the stack parameters from both NEIs to retain only stacks that report emissions for the pollutants we model (formaldehyde in the case of the NEI for HAPs and primary $PM_{2.5}$ in the case of the NEI for criteria pollutants) and that had electricity and/or cogeneration SCCs associated with them. Since both NEIs also report emissions from fugitive releases, we eliminated those "stacks." Only the latter two criteria were applied to the NET database since stack parameters are not associated with specific pollutant emissions in the NET.

After application of the inclusion criteria, we looked for consistency across all three sources of stack parameters. We gave preference to original parameters from the NEI (HAPs). We made sure to include stack parameters for every unique SCC. We were careful not to include duplicative stacks when multiple agencies reported emissions for

[20] It is possible for DG technologies to be located on the roofs of buildings. Even though the effective stack height above the building would still only be on the order of five meters, the height of the building would add considerably to the release height as used in Gaussian plume modeling. However, this placement is less likely since it would be easiest for DG to be located on ground level to connect to the existing, high-pressure, natural gas distribution network (Energy Nexus Group, 2002).

the same source. [21] When available, we also checked our estimate of the total number of stacks against photographs of the plant. Finally, for modeling efficiency, if there are two or more stacks with nearly identical heights and other parameters, we model them as if they were one stack. [22] In all, we modeled 64 stacks for the 37 existing units assessed.

To calculate effective stack height requires data on the wind speed at the physical stack height. Since many cases have elevated stacks, we adjusted the wind speed to the height of the physical stack. An empirical power law relationship is often used to estimate wind speed as a function of height (Seinfeld and Pandis, 1998)

$$\frac{\overline{u}_h}{\overline{u}_r} = \left(\frac{z_h}{z_r} \right)^p \tag{4}$$

where, u_h is the mean wind speed (m/s) at release height, h (m); u_r is the mean wind speed (m/s) at the reference height, r (m); z_h is the height (m) of release; z_r is the reference height (typically 10 m); and p is the power law exponent (-). Irwin (1979) provided estimates of p for four roughness lengths (z_o) and six Pasquill stability classes. Following the approach of Hanna *et al.* (1982), we consolidate the four roughness length categories into two that are characteristic of urban and rural areas, as shown in Table 17.

Finally, for those existing units that have multiple stacks, we use a weighted sum approach to estimate the plant-average intake fraction from all associated stacks. The weights are determined as the contribution of a single stack to the total volumetric flow of all electricity generation and cogeneration-related stacks (a stack parameter reported in both NEIs and the 1996 NET).

For the existing units, Tables 12-14 report the stack parameters used in modeling. Table 16 reports analogous information for the small-scale DG technologies (< 1 MW).

Emissions and Emission Factors for Existing Units and New Central Stations

Emissions data are necessary to calculate the emission factors for each pollutant, which are used to determine the intake-to-generation ratio, the mass of a pollutant inhaled by the exposed population per kilowatt-hour delivered to the site of use. Emission factors are estimated for each existing unit based on 1999 emissions data, the latest available. These are used to establish baseline intake-to-generation ratios for the current mix of EGUs in California. Since new DG could displace production from either existing units or new ones, we require emission factors for new central stations to estimate intake-to-generation ratios for these new units. Thus, we estimate emission factors for new combined-cycle turbines, the most popular technology for new central stations, assuming these new combined-cycle turbines would be located at the same sites and have the same stack configurations as the existing units, and thus the same intake fractions.

[21] The NEI allows multiple agencies to report non-duplicative emissions for a single source. However, we believe that when stack parameters are identical for emissions reported by different agencies, the stack information is likely duplicative. Thus, we eliminated those entries we considered duplicative. When reported by the same agency, identical entries were accepted as two identical stacks.

[22] Moss Landing, for example, has two very tall (152 m) stacks that are modeled as one. By the time the plume has reached the ground, the plume width from each stack is an order of magnitude or more greater than the distance between the stacks. This justifies treating the emissions as if they were emitted from just one stack.

Table 17. Power law exponents (*p*) for wind speed adjustment in urban and rural areas.

Stability Class	Rural z_o = ~0.10 m	Urban z_o = ~1.00 m
A	0.08	0.22
B	0.09	0.22
C	0.11	0.25
D	0.16	0.32
E	0.32	0.42
F	0.54	0.65

For each existing unit, emissions of formaldehyde come from the 1999 NEI for HAPs and, for primary $PM_{2.5}$, from the 1999 NEI for criteria pollutants (EPA, 2003b and EPA, 2004b, respectively). We only consider emissions associated with electricity generation or cogeneration-related SCCs to not bias against those EGUs for which combustion is used for many purposes. For instance, a wood products company that generates electricity from combustion of the waste wood (whether for cogeneration purposes or not) would have a significant fraction of its emissions associated with production of timber products. Comparing facility-level emission factors of an EGU with non-electricity-related products to one without would be inappropriate.

Exceptions were made for three of five existing units with no electricity or cogeneration-related primary $PM_{2.5}$ emissions in the NEI. In these three cases, we substituted facility-level $PM_{2.5}$ emissions reported in CARB's Facility Search Engine of their 1999 emissions inventory (CARB, 2004b). Two of these three cases are for plants that only generate electricity (Coachella and Magnolia). For the one whose emissions do not necessarily reflect only electricity generation (San Antonio Community Hospital, cogeneration station), the emission factor we calculate is similar to other cogeneration units. The two other existing units with no primary $PM_{2.5}$ emissions in the NEI did not have $PM_{2.5}$ emissions reported in the CARB database either. Thus, we cannot calculate an emission factor or the intake-to-generation ratio for primary $PM_{2.5}$ for these plants.

While we did calculate emission factors for cogeneration plants, those results will not be used to estimate IGRs. Three of our cogeneration cases burn relatively dirty fuels – coal, petroleum coke and wood waste. We would expect their PM emissions to be high relative to units that burn natural gas. Instead, the emission factors were orders of magnitude lower. Most of these units produce products other than just electricity. Owing to the concern expressed above that it would be unfair to compare the facility-level emissions of a source with many non-electricity products to one solely producing electricity, we have decided not to use the emission factors for the cogeneration plants until we gain more confidence in their accuracy.

In the case of electricity generation, emission factors typically express the mass of pollutant emitted either per unit of heat input or per unit of electricity output. If emissions per unit heat input are reported, knowing the thermal energy-to-electricity conversion efficiency allows one to calculate the emission factor per unit of electricity generated. For the existing units, we calculated the efficiency from heat input and electric output data provided by eGRID (EPA, 2003a).

Central station emission factors also need to be adjusted to account for the loss of electricity between where it is generated and where it is used (i.e., line loss). Electricity is converted to heat owing to resistance (R) in the transmitting media and the amount of current (I). ($P_h=I^2R$; where P_h is power, which in this case is the rate of production of heat energy or electric power loss.) This loss is a function of both distance (directly proportional to R) and voltage (V) (inversely proportional). [23] DG is superior to central stations on both counts. By definition, central station plants are more distant from where the electricity will be used than DG. In addition, by connecting to the customer side of the meter — the formal definition of DG (Ackermann *et al.*, 2001) — DG units avoid the distribution part of the network, which has the lowest voltage. This latter factor is the

[23] With constant electric power demand, lower voltage requires increased current ($P_e = IV$; where P_e is electric power).

more important one as a greater proportion of line losses occur in the distribution network than in the high-voltage, long-distance transmission lines (Ackermann *et al.*, 2001). For the purposes of this assessment, we applied average line losses of 10% to electricity generated by central station plants and 0% for both the existing DG (> 1 MW) and hypothetical DG (< 1 MW) technologies (EIA, 1999; CARB, 2001a). Thus, knowing the emissions, heat input, efficiency and line loss, we calculated emission factors in milligrams of a pollutant emitted per kilowatt-hour of electricity delivered (mg/kWh_{del}). These results are reported in Tables 12-14 for all existing units.

Hypothetical combined-cycle central stations are considered to complete the comparison of what DG technologies might displace if there is the shift in electricity generation paradigm that many predict. In terms of future capacity additions, especially in California, seemingly the only central station combustion technology with which DG technologies will be competing is combined-cycle gas turbines. These plants are similar in many respects to traditional central stations — fuel consumed, types of pollutants emitted, stack heights, and siting preferences — but are more efficient and emit at rates comparable to or better than the most well-controlled existing central stations. [24] Thus, they provide a 'best' central station case for the comparison of population intake of atmospheric emissions to alternative scales and technologies from which to generate electricity.

New central station plants in California are required to meet the CARB best available control technology (BACT) standard for five pollutants: NO_x, CO, VOC, PM_{10} and SO_2 (CARB, 1999). In the case of PM_{10}, CARB's BACT recommendation is written as a limit on the amount of sulfur in natural gas. This formulation presents difficulties in translation to units of particulate mass emission per kilowatt-hour. Instead, we used the requirements placed on a particular power plant that recently underwent BACT review (Carson Energy Group, Sacramento, CA) to estimate their $PM_{2.5}$ emissions (CARB, 1999), assuming all primary emissions of PM from natural gas combustion are in the form of $PM_{2.5}$ (EPA, 2000a). We then assume that other new central station plants will be required to achieve similar emission levels. The BACT primary $PM_{2.5}$ emission factor is thus estimated to be 12.5 mg/kWh_{del}.

Since there is no CARB BACT standard for formaldehyde, an emission factor was obtained from AP-42 (EPA, 2000a) for natural gas turbines, adjusted for the higher efficiency of combined-cycle units (51%) (RAP, 2001). In this case, we assume that all new central stations would be able to achieve an emission factor equivalent to natural gas turbines with catalytic reduction control technology installed. The primary HCHO emission factor that we refer to as BACT is estimated to be 0.067 mg/kWh_{del}.

A comparison of emission factors for primary $PM_{2.5}$ and HCHO between the two types of existing units for which we have confidence in their emissions (central stations and existing DG (> 1 MW)) is presented in Figures 13 and 14. Figure 15 displays $PM_{2.5}$ emission factors for the three fuel types used by the central stations and existing DG (> 1 MW). Figures 16 and 17 highlight the differences in $PM_{2.5}$ and HCHO emission factors between those existing and new central stations and the hypothetical DG (< 1 MW) technologies.

[24] Assuming that regulations will require installation of control technologies such as selective catalytic reduction for NO_x control.

The comparisons between case types and fuels shown in Figures 13 - 15 mostly conform to expectation. The central tendency in emission factor for both pollutants is higher for the existing DG (> 1 MW) units than central stations, likely owing to better control technologies and tighter permitting requirements for the central stations. The median emission factor for natural gas units is a factor of 50 lower than for oil-burning units. The cases we selected of landfill gas (LFG)-burning units display a lower median emission factor than for natural gas units, which is surprising. However, it should be remembered that there are only three LFG units with reported emissions for primary $PM_{2.5}$, making broad generalizations inappropriate. Another interesting finding is that the variability within case types and fuels is often greater than that between types or fuels. A notable exception to this observation is for the central stations and natural gas-burning units (which most central stations are), which both exhibit rather tight interquartile ranges. This observation is echoed in the results presented later in the report.

Cases that appear to be outliers are also interesting to note. [25] The Magnolia central station, although burning natural gas, has the highest emission factor for $PM_{2.5}$, almost 100 times the median for central stations. Pebbly Beach has nearly as high a $PM_{2.5}$ emission factor, which is possibly more understandable since it burns diesel fuel. The Valley central station has an extraordinarily low $PM_{2.5}$ emission factor. Other possible outliers for $PM_{2.5}$ emission factor are Kearny (burning NG and some diesel), North Island (NG and some diesel) and Oakland (diesel), all of which emit at ten or more times the median rate. Two EGUs appear to be high outliers for HCHO emission factor: Kearny and Salinas (LFG) at 30 and 150 times the median in their respective case category. Two others appear to be low HCHO emission factor outliers: Riverside Canal (NG) and Marina (LFG), emitting at 780 and 275 times lower than the median emission factor in their respective case categories. Three other central stations have conspicuously low HCHO emission factors and could possibly be outliers: Puente Hills (LFG), Redding (NG) and Morro Bay (NG and some diesel). In many cases, notably high or low emission factors foretell an EGU's relative ranking in intake-to-generation ratio.

Examining Figures 16 and 17, we find that while the median emission factor for existing central stations is greater than if those units were BACT-controlled, there are some existing units with considerably lower emission factors than even BACT-controlled units (i.e., Valley (for $PM_{2.5}$) and Morro Bay, Puente Hills and Riverside Canal (for HCHO)). The latter cases are at least outliers or possibly a result of erroneous reporting or compilation of emissions. This observation will be noted again when we calculate the intake-to-generation ratios for the existing units.

Finally, in the analysis reported here, we assume that all cases operate at the specified emission factor for every hour of a year. In truth, all plants have some number of days during every year when they are out of service. Some plants have a considerable proportion of annual hours in non-operation as they modulate output to follow system load or peaks. There are two concerns with regard to the constant emission factor assumption. First, our results may be biased if there is some correlation between periods of non-operation and meteorological conditions. [26] Our assumption likely overestimates emissions during periods of poor dispersion (low system electricity demand occurs

[25] These cases are most easily noted in Tables 12 and 13.

[26] There could also be correlations between emissions and population breathing rate and/or population density. Incorporating variability in both of these parameters could be a useful line of future research.

during the night when mixing heights and wind speeds are low). This could lead to an overestimation of population intake, the magnitude of which is inversely related to the plant's capacity factor (i.e., the less generation occurs during off-peak hours, the greater the bias).

Second, because emission factors are based on typical operating conditions (e.g., full load, steady-state operation), our assumption of constant emission factor could under- or over-estimate true annual-average population intake per unit electricity delivered. Every period of non-operation has associated start-up and shut-down emissions. Emission factors for start-up and shut-down conditions can be considerably higher than those under steady-state operations (CARB, 1999 and EPA, 2000a). In addition, it is unlikely that even baseload plants will operate at full-load for all operable hours. The effect of load on emissions varies by technology, pollutant and the presence of control technologies, where part-load conditions can increase or (more rarely) decrease emission factors considerably (CARB, 1999 and EPA, 2000a).

To the extent that many of the largest power plants in California use continuous emission monitors (CEMs), the emission factor we calculate accounts for all non-steady-state emission conditions. For these plants, a concern of bias regarding any potential correlation of these non-steady-state conditions with certain meteorological conditions remains. For all other existing plants (whose emissions reported to the EPA are allowably estimated by multiplying a typical emission factor by the electricity generated), some uncertainty owing to inaccurate determination of true emissions is introduced in our estimate of population intake, the magnitude of which is related to the proportion of hours under non-steady-state conditions. To understand the true population inhalation exposure per unit of electricity delivered, we would need an hourly time series of both emissions and generation. This level of detail is rarely reported.

Emission Factors for Hypothetical DG Technologies

Emission factors for DG technologies have been reported in many sources (e.g., Allison and Lents, 2003; RAP, 2001; Iannucci *et al*., 2000; Energy-Nexus Group, 2002). There is wide variability amongst these sources, leading to uncertainty in how best to model DG emissions. A recent review produced best estimates of emission factors for a number of pollutants over a range of DG technologies (Samuelsen *et al.*, 2003). These emission factors are reported for the existing stock (i.e., not necessarily meeting CARB's DG emission standards) and also at levels that meet the 2003 and 2007 CARB emission standards. This report forms the basis of our selection of primary $PM_{2.5}$ emission factors, which are listed for each technology in Table 16 and displayed in Figure 16.

Since most authors writing on the air quality impacts of DG have focused on criteria air pollutants, there is no emission factor specific to formaldehyde available. [27] In this assessment, we use values from the most widely used emission factors handbook, EPA's Compilation of Air Pollutant Emission Factors, otherwise known as AP-42 (EPA, 2000a). Most small-scale DG technologies are either directly represented in AP-42 (diesel and NG ICEs and NG turbines) or significantly related to a more mature technology (microturbines). Fuel cells are different enough from other electricity

[27] Total VOC emissions are reported in the Samuelsen *et al.* (2003) review. One could speciate these values to estimate HCHO emission factor. It is unclear whether this approach would lead to greater or lesser uncertainty in emission factor then the approach we currently use.

generation technologies that we do not attempt to estimate a formaldehyde emission factor. Scaling the AP-42 factors (reported in pounds per million British thermal units, lbs/MMBtu) by the efficiency of each small-scale DG technology (Samuelsen *et al.*, 2003) provides the emission factors in units of mg/kWh_{del}. These values are tabulated in Table 16 and displayed in Figure 17.

As seen in Figures 16 and 17, there is variability in the existing central station category because each case has its own emission factor, whereas each of the other technologies (and BACT) has only a single emission factor characteristic of that technology/standard.

We should note that both of the concerns raised in the previous section regarding how the constant emission factor assumption may over- or under-estimate true population intake are relevant to our estimation of population intake from the hypothetical use of DG technologies in baseload capacity.

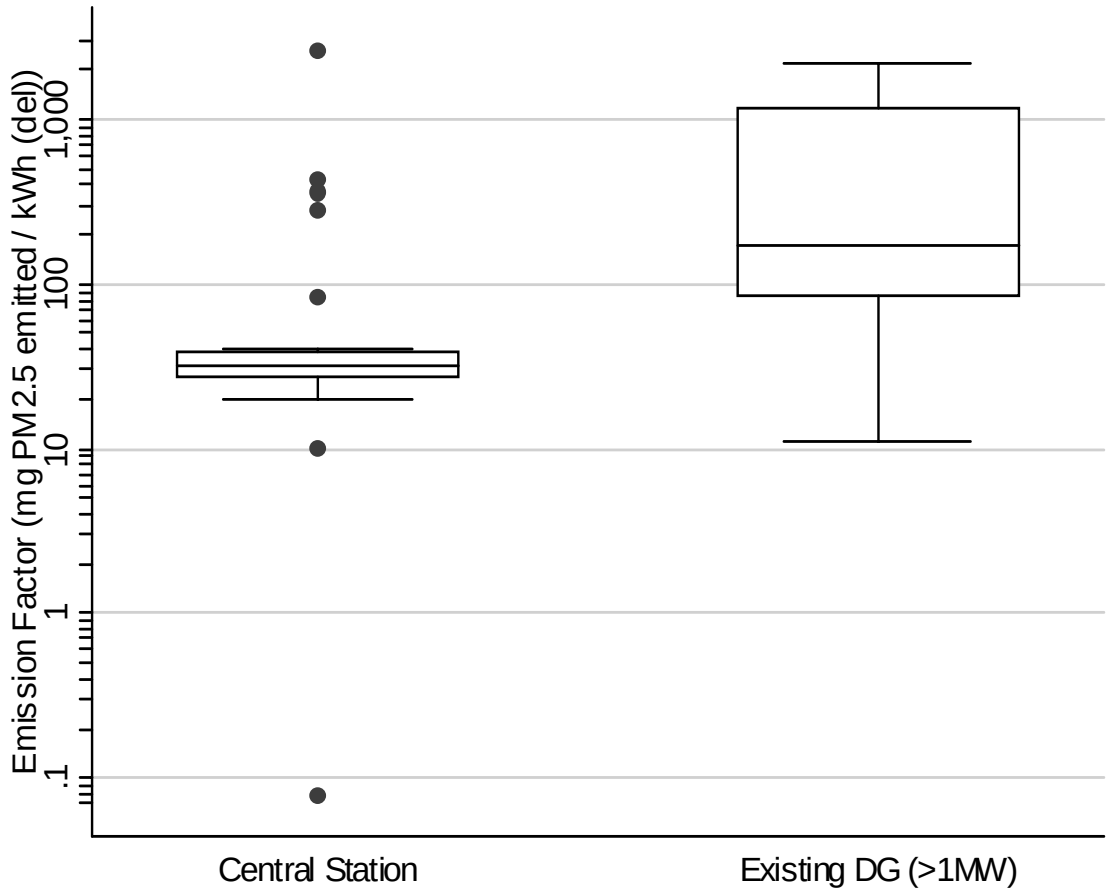

Figure 13. Interquartile box plots of emission factor for primary $PM_{2.5}$ for two types of existing sources: central stations and existing DG (> 1 MW) (n(CS) = 25, n(DG (> 1 MW)) = 4). Cogeneration cases are not shown owing to uncertainty in emissions. Two additional existing DG (> 1 MW) cases had no reported PM emissions. The emission factors are all from reported emissions in 1999 (EPA, 2004b). (See Figure 9 caption for interpretation of the interquartile box plot.)

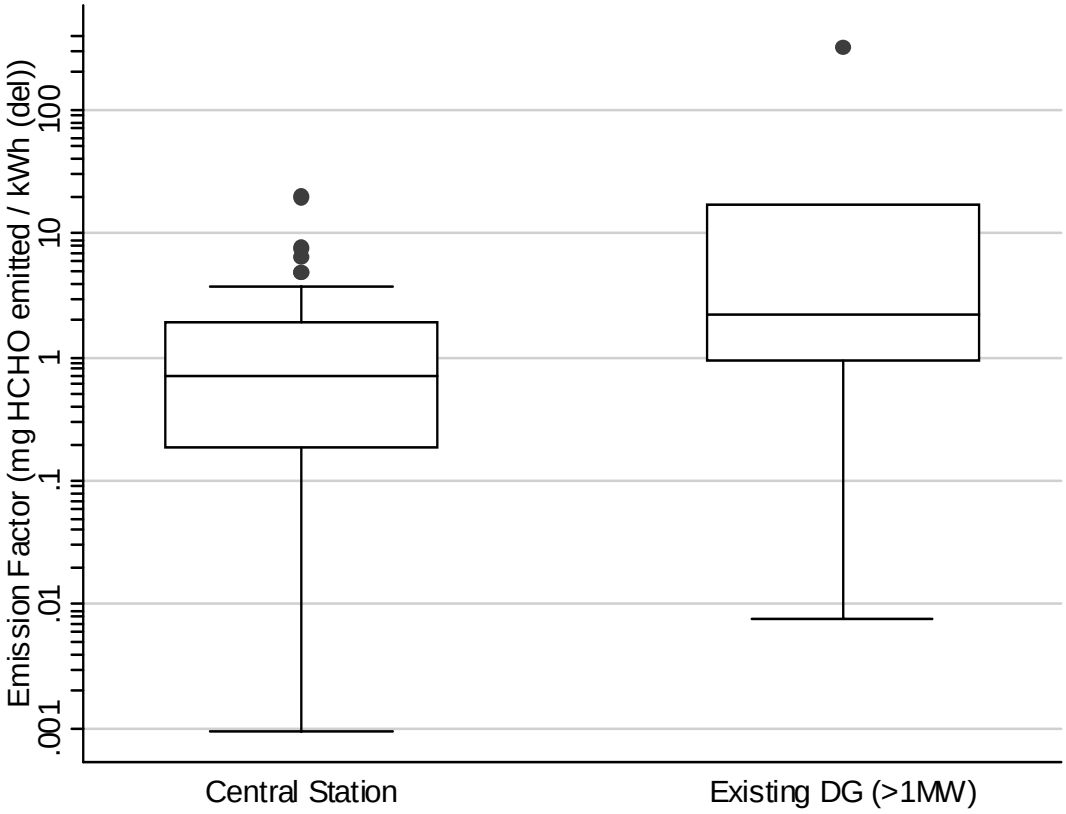

Figure 14. Interquartile box plots of emission factor for primary HCHO for two types of existing sources: central stations and existing DG (> 1 MW) (n(CS) = 25, n(DG (> 1 MW)) = 6). Cogeneration cases are not shown owing to uncertainty in emissions. The emission factors are all from reported emissions in 1999 (EPA, 2003b). (See Figure 9 caption for interpretation of the interquartile box plot.)

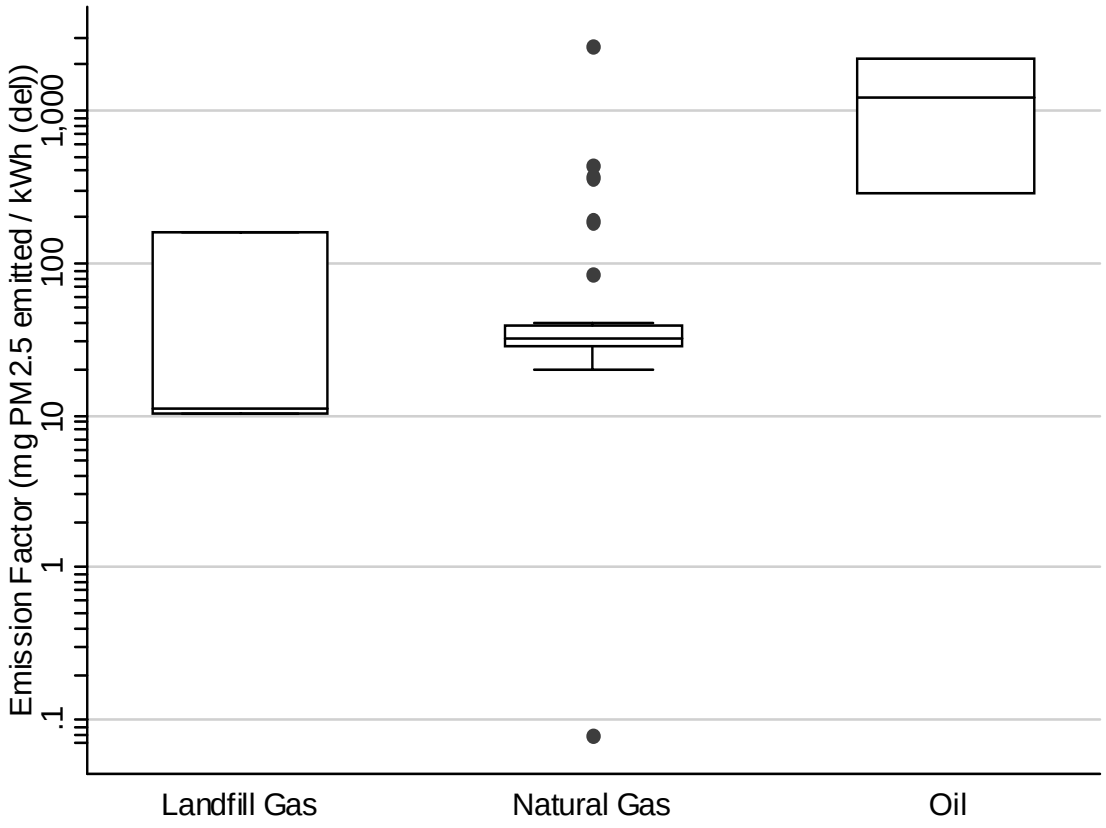

Figure 15. Interquartile box plots of emission factor for primary $PM_{2.5}$ for three fuels used by the existing source cases in this assessment (n(Landfill Gas) = 3; n(NG) = 24; n(Oil) = 2). Cogeneration cases are not shown owing to uncertainty in emissions and two existing DG (> 1 MW) cases had no reported PM emissions (both of which use landfill gas). The emission factors are all from reported emissions in 1999 (EPA, 2004b). (See Figure 9 caption for interpretation of the interquartile box plot.)

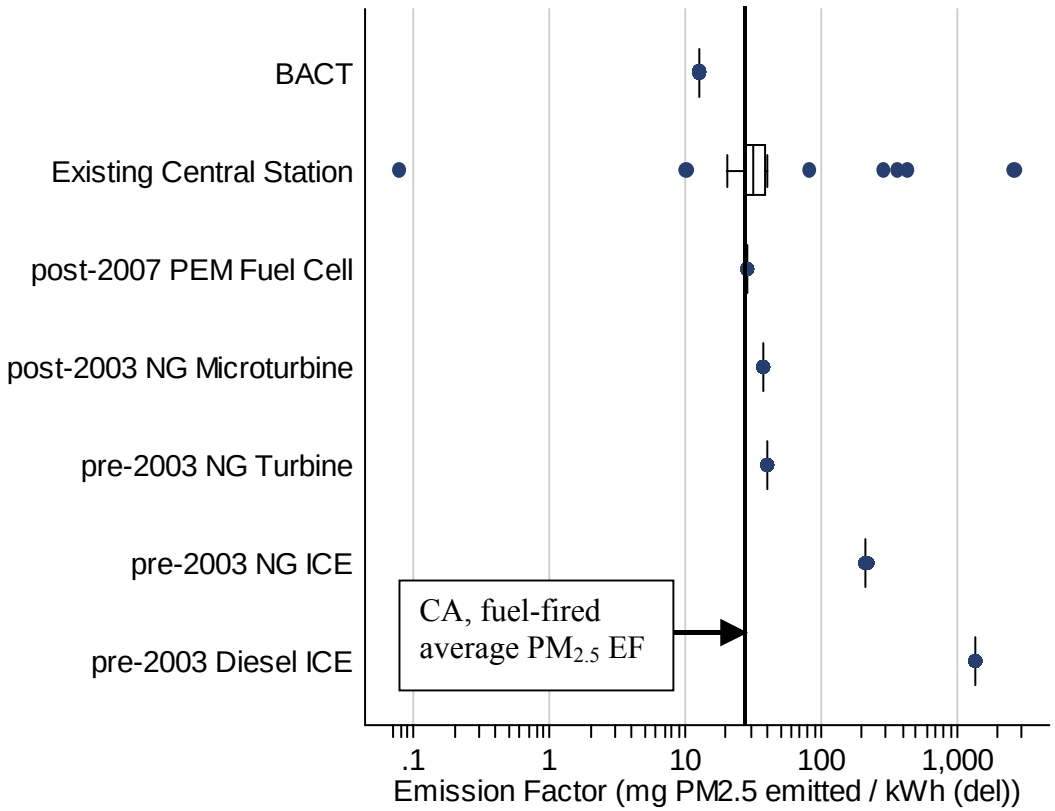

Figure 16. Emission factor for primary $PM_{2.5}$ for existing central station cases and hypothetical DG cases, by technology, plus California BACT regulated for new central stations. The existing central station group (n = 25) is plotted as an interquartile box plot based on actual emissions and generation in 1999 (EPA, 2004b). (See Figure 9 caption for interpretation of the interquartile box plot.) The emission factor for each DG technology and BACT is the best available in the literature (BACT: CARB, 1999; all hypothetical DG (< 1 MW) technologies: Samuelsen *et al.*, 2003). California average $PM_{2.5}$ emission factor for fuel-fired EGUs is provided for reference (CEC, 2004b).

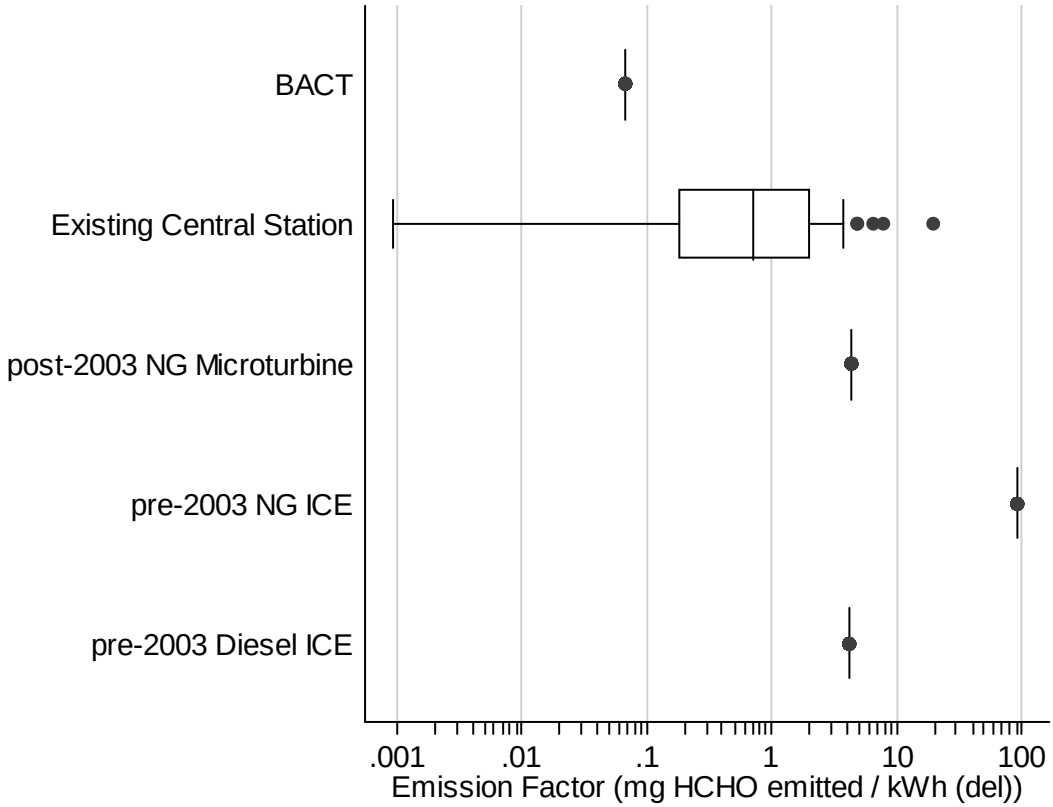

Figure 17. Emission factor for primary formaldehyde (HCHO) for all existing central stations and hypothetical DG cases, by technology. The existing central station group (n = 25) is plotted as an interquartile box plot based on actual emissions and generation in 1999 (EPA, 2003b). (See Figure 9 caption for interpretation of the interquartile box plot.) The fuel cell is not shown because there is no available emission factor. The natural gas turbine is not shown because its emission factor is the same as the microturbine, adjusted by its characteristic efficiency. The emission factor for each technology is the best available in the literature (BACT: EPA, 2000a (for a combined-cycle turbine with catalytic reduction); all hypothetical DG (< 1 MW) technologies: EPA, 2000a).

II.C.5 Pollutant Data

Two pollutant classes are considered. Because conserved pollutants, by definition, undergo no transformations, no pollutant-specific data are needed in the Gaussian model to predict downwind concentrations normalized by emission rate. Decaying pollutants can be accommodated in Gaussian models with an exponential decay term, $e^{-kx/U}$. The decay constant, k, represents the sum of the rate constants for all relevant loss mechanisms. In the case of formaldehyde, there are two reactions that contribute to the decay of this species on timescales of interest: photolysis and reaction with the hydroxyl radical (OH) (Atkinson, 2000). [28]

The photolysis rate depends on solar intensity, which, in turn, varies with the time of day and year, and with latitude. Using data from Demerjian *et al.* (1980) on rates by zenith angle and path, and from Finlayson-Pitts and Pitts (1986) correlating zenith angle and time of day for Los Angeles, we estimated the average photolysis rate for 'typical' conditions during the six hours symmetric around noon.

Formaldehyde reaction with the OH radical is a first-order process. With data from Finlayson-Pitts and Pitts (1986) on OH concentration across a range of background pollution levels and the International Union of Pure and Applied Chemistry (IUPAC) recommended reaction rate (IUPAC, 2001), we estimated the reaction rate for two general pollution conditions – moderate and low – which we take to correspond to the urban and rural designations, respectively. While heavily polluted may better describe the atmospheric conditions within cities than moderate, we use moderate conditions for sources located in cities because it is a better estimate of the average conditions over the total travel distance of the plume. Each OH background pollution level is reported over a range of concentrations; we used the high end of each range since California is such a highly polluted state. Table 18 summarizes the reaction rates used for formaldehyde decay as well as their underlying bases.

Neither photolysis nor reaction with OH is a significant HCHO loss mechanism at night compared to the residence time of the plume within our modeling domain (Atkinson, 2000). Therefore, HCHO emitted during the night is considered conserved; HCHO emitted during the day undergoes first-order decay at a rate appropriate to the urban/rural modeling designation. Since we assume constant emissions from all EGUs, a plume encounters an equal proportion of daytime and nighttime conditions. Thus, the arithmetic average of intake fraction for daytime and nighttime conditions is used to achieve an estimate of annual-average intake fraction for HCHO.

[28] In this assessment, we did not consider reaction with the nitrate radical (NO_3) or dry or wet deposition of HCHO. Reaction with NO_3, while the only significant loss mechanism during night, is insignificant compared to losses by OH and photolysis during the day (Atkinson, 2000). Our central estimate for the effect of dry deposition on HCHO concentration is 30% loss within 100 km (using data from Christensen *et al.*, 2000); this is small in comparison to the central estimate of 30-50% per hour loss by reactions. In future assessments, the role of dry and wet deposition would be worth exploring in more detail.

Table 18. Total daytime rate constant for HCHO decay considering reaction with the hydroxyl radical (OH)[a] and photolysis (rates used in modeling in bold).

Photolysis (HCO and H_2 paths)		**Total daytime rate constant (h^{-1})**			
		Atm Condition--Low Pollution (rural) [b]		Atm Condition--Moderate Pollution [b]	
Zenith Angle[c]	Rate (h^{-1})	High End	Low End	High End	Low End
30^o	0.27	0.35	0.28	0.60	0.31
65^o	0.10	0.19	0.11	0.43	0.15
45^o	0.21	**0.30**	0.22	**0.54**	0.25

[a] OH + HCHO reaction rate: 9.2×10^{-12} cm^3/(molec s) (IUPAC, 2001)

[b] [OH] (rural) = 2.5×10^6 molec/cm^3; [OH] (moderate) = 9.8×10^6 molec/cm^3 (high end of each concentration range) (Finlayson-Pitts and Pitts, 1986).

[c] 45^o is the zenth angle at 10am/2pm on the equinoxes in LA. This typical value represents approximately the average conditions for the 6 hour block symmetric around noon.

II.D Modeled Parameters

II.D.1 Intake Fraction

A figure of merit for assessing differences in population exposure owing to choice of electricity generation paradigm — central station or DG — is the intake fraction (iF). An iF is the fraction of an emitted pollutant that is inhaled by all exposed people, defined by Lai *et al.* (2000) as

$$iF = \frac{\text{mass inhaled (by all exposed persons)}}{\text{mass emitted}} = \frac{\sum_{people} \int C(t) Q_B(t) dt}{\int E(t) dt} \quad (5)$$

where $C(t)$ is the time-varying concentration within the breathing zone attributable to the emission source (g/m^3), $Q_B(t)$ is the time-varying breathing rate (m^3/h) and $E(t)$ is the emission rate of the pollutant from the source in question (g/h). For steady releases and constant transport and transformation conditions, the numerator and denominator can be expressed as constant rates:

$$iF = \frac{\text{mass inhalation rate}}{\text{mass emission rate}} = \frac{\sum_{people} CQ_B}{E} \quad (6)$$

The concept of a ratio of inhaled mass to emitted mass has been used for over a decade, often under different names (see Bennett *et al.*, 2002 for a historical summary). The iF metric combines the results of pollutant fate and transport analysis with an exposure assessment to express the emissions-to-intake relationship in a single, dimensionless and intuitive value. Results for ambient emissions are usually expressed *per million*, e.g., grams of $PM_{2.5}$ inhaled per metric ton emitted. [29] Principally, the iF depends on three factors: 1) the **proximity** between the source and the receptors; 2) the **persistence** of the pollutant emitted; and 3) the **population** density in the receptor region. Thus, the iF is more *site-specific* than *technology-specific*. For instance, in the Gaussian plume model, the intake fraction does not depend on the emission rate since it appears in both the numerator of the concentration equation (eq 1) and the denominator of eq 5.

The iF concept can be applied to evaluate source-receptor relationships for an individual, a group of individuals, or the entire exposed population. In this report, the entire downwind exposed population within 100 km will be considered. In the future work, one could explore the apportionment of iF among selected subpopulations.

A few features of the iF are noteworthy, especially in contrast to alternative methods of estimating risk from electricity generation stations. A traditional approach to estimating the risk posed by HAP emissions from large point sources involves estimating

[29] Indoor releases usually lead to iFs of order thousands per million, because of slower removal by airflow and smaller mixing volumes (Lai *et al.*, 2000).

the lifetime intake of a hypothetical person who breathes the maximum ground-level concentration (in both time and space) of a pollutant (e.g., AB 2588, 1987). This person is termed the maximally exposed individual (MEI). If the risk to the MEI is above a regulatory threshold, action must be taken to reduce the maximum concentration. This method is reasonably well-suited for an assessment of theoretical, maximal risk from large point sources and is often employed for the purpose of permitting air emissions.

While the MEI approach may be protective of public health, it does not provide a realistic estimate of actual population exposure. Also, when contemplating the implications of a shift from a few, large point sources to numerous, small, distributed sources, a regulatory model based on the former is not likely to recognize the potentially significant public health risks of the latter, i.e., there is a *de minimus* project size below which no MEI evaluation is required and, thus, no risk is assumed. Large numbers of small sources can lead to significant cumulative risk even if each is below the *de minimus* level. The iF metric is not so limited. It is equally well-suited to evaluating the source-intake relationship for small, distributed sources as it is for large, point sources.

Another method used to assess risk is to estimate the population exposed to ambient concentrations above a reference concentration. The reference concentration is typically set at a *de minimus* risk threshold, say, one per million for lifetime cancer risk. For pollutants with a no threshold dose-response, there is still attributable risk for those exposed to concentrations below the reference concentration. The sum of individual risk below this threshold could be a significant fraction of the total population risk. The iF reflects total population exposure and, thus, includes what could be a substantial cumulative burden.

By accounting for the total population intake, for those compounds with a linear, no-threshold dose-response relationship, the population health impact is proportional to the iF (or population intake). Thus, the iF can be used to evaluate the relative risk of multiple sources. Notwithstanding its potential utility for this purpose, we will not undertake to estimate population health impact in this study, focusing rather on the relative levels of human intake per unit electricity delivered as an important intermediate result that can serve as an indicator of the scale of adverse health effects.

II.D.1.a Intake Fraction for Conserved Pollutants

We calculate iFs for conserved pollutants based on the method of Lai *et al.* (2000). Incorporating the Gaussian equation (eq 1) for time-averaged, ground-level downwind concentrations into eq 6, yields the following expression

$$iF = Q_B \iint \frac{P}{\pi \sigma_y \sigma_x U_E} \exp\left(-\frac{y^2}{2\sigma_y^2}\right) \exp\left(-\frac{H_E^2}{2\sigma_z^2}\right) dx dy \qquad (7)$$

where P is the population density (people/m^2) and Q_B is the individual breathing rate (m^3/s). The limits of integration are infinite in the y-direction and, for this assessment,

from 0 km to 100 km in the *x*-direction. [30] As discussed in section II.C.1.a, σ_z is capped at the mixing height.

Implicit in eq 7 is the assumption that the ground-level concentration calculated by the Gaussian plume model can be used as an estimate of the concentration in the breathing zone. For outdoor exposures to ambient concentrations, this assumption is reasonable. However, for certain pollutants such as $PM_{2.5}$, being indoors offers some protection against pollutants of outdoor origin (Riley *et al*., 2002). To the extent that buildings are protective, our approach will overestimate the true intake fraction. However, it will do so in a largely consistent manner among different technologies, so that the proportional change in intake fraction across scenarios should not be biased.

By assuming infinite plume spread and constant population density in the transverse direction, eq 7 can be integrated analytically in the *y*-direction and numerically in the *x*-direction.[31] The reduced expression for the iF of a conserved pollutant, including ground and mixing height reflection is

$$iF = \frac{\sqrt{2}Q_B}{\sqrt{\pi}U_E}\int_0^{X_{max}} \frac{P}{\sigma_z}\left\{\sum_{-n}^{n}\exp\left[-\frac{\left(2nM - H_E\right)^2}{2\sigma_z^2}\right]\right\}dx \qquad (8)$$

The limit of integration is 0 to x_{max} = 100 km in the *x*-direction. The number of reflections (n) is determined by a convergence test: when the intake fraction does not increase more than 1% across the last three reflections calculated, the summation is stopped.

Assuming constant population density in the transverse direction introduces some uncertainty owing to lateral plume spread downwind. The merit of this assumption may be further diminished by the census tract-level resolution of population density. However, since the 120 directions were chosen without regard to specific downwind populations, population density off-vector at a given downwind distance is not expected to be systematically different than that on-vector. Therefore, this assumption may contribute to imprecision in our estimates, but is not expected to contribute to inaccuracy.

It is worth reiterating that the iF results for conserved pollutants are not dependent on the particular pollutant chosen. This independence is apparent in eq 8. Because intake fractions are normalized by the pollutant-specific emission rate, the modeled iF only depends on transport (U), dispersion (σ_z), plume rise (H_E) and population parameters (P, Q_B). Thus, the results for conserved pollutants apply to this entire class of pollutants.

II.D.1.b Intake Fraction for a Decaying Pollutant

Intake fractions for first-order decaying pollutants can be calculated by inserting Gaussian-predicted concentrations modified by an exponential loss term into eq 8.

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[30] Although mathematically the integration limits on *y* are -∞ to +∞, most of the area under the curve lies within ± 2 σ_y of the centerline of the plume. At a distance of 100 km downwind of the source, σ_y varies between 2 and 10 km, depending on stability class. Thus, the effective limits of integration in the *y* direction are less than +/- 20 km from the plume centerline.

[31] We used a trapezoidal, numerical integration scheme with a step size of Δx = 0.5 km.

$$iF = \frac{\sqrt{2}Q_B}{\sqrt{\pi}U_E}\int_0^{X_{max}} \frac{P}{\sigma_z}\left\{\sum_{n=-20}^{20}\exp\left[-\frac{\left(2nM - H_E\right)^2}{2\sigma_z^2}\right]\right\}e^{-kx/U_E}dx \qquad (9)$$

Here, a pollutant-specific parameter is introduced, the rate constant for decay (k).

II.D.1.c Intake Fraction Model

To expedite the estimation of intake fraction for such a large number of cases as selected in this assessment, we created a computer-based model called IntakeFractionCalc.xls (iFCalc). iFCalc is an Excel Macro coded in VisualBasic. This program can estimate intake fraction for conserved or decaying pollutants for a point source of any number of stacks using the urban/rural and elevated/ground-based modeling designations as described in this report. Simultaneously, it calculates intake fraction for a co-located distributed generation source. It reads in text files of population density in rays from a source location as well as meteorological inputs, and it is flexible to the structure of the input files. All parameters used in the intake fraction equations (e.g., breathing rate, dispersion parameters, mean building height) can be easily adjusted by the user. iFCalc produces hourly effective stack height and intake fraction per stack as well as weighted average intake fraction across an entire annual cycle. Incremental intake fraction by radial distance downwind is also reported. Finally, all user inputs can be saved for re-running and are reported in the output file for easy reference. The model and a user's guide are available from the authors upon request.

II.D.2 Intake-to-Generation Ratio

To make the results of the iF assessment technology-specific and to account for some of the benefits of DG, e.g. reduced line loss, the pollutant-specific iFs are multiplied by appropriate emission factors. This method yields a parameter we call the intake-to-generation ratio (IGR), which quantifies pollutant intake per unit of electricity delivered. It can be used like an emissions factor to assess the potential damage of an activity (e.g., mass emitted) with knowledge only of its intensity (e.g., electricity generated). In this case, the intake-to-generation ratio indicates the population intake (grams inhaled) of air pollutants emitted because of the delivery of a certain amount of electricity to where it is used.

In equation form,

$$IGR = EF \times iF = \frac{\text{population intake } (mg_{inhaled})}{\text{electricity delivered } (kWh_{delivered})} \qquad (10)$$

where EF is the emission factor expressed in pollutant mass emitted per unit electricity delivered ($mg_{emitted}/kWh_{del}$). This figure of merit will be used as the ultimate point of comparison among the cases in our research.

III. Results and Discussion

Differences in population exposure to air emissions from the two paradigms of electricity generation — central station and DG — are examined through the use of intake fractions and intake-to-generation ratios. We use the intake fraction to explore the relative exposure intensities (mass inhaled per mass emitted) from the different paradigms of electricity generation. We then normalize our site-specific intake fractions by appropriate emission factors to achieve technology- and pollutant-specific intake-to-generation ratios. These results are used to compare the power plants and technologies in terms of pollutant mass inhaled per unit of electricity delivered. Intake fraction and IGR results are presented graphically in sections III.A and III.B, respectively. Section III.C presents estimates of the emission factors necessary for new, small-scale DG (< 1 MW) to equal the exposure burden (i.e., IGRs) of either existing central stations or central stations meeting California BACT emission standards. Finally, numerical results of both parameters are tabulated along with emission factors in the summary of results (section III.D).

III.A Intake Fraction Results

III.A.1 Conserved Pollutants Intake Fractions

III.A.1.a Existing Units

The distributions of intake fractions for the 25 central stations, along with the cogeneration and existing DG (> 1 MW) cases, are presented in Figure 18. Recall that the results in this section are applicable to any conserved pollutant as no pollutant-specific parameters enter into the evaluation.

Figure 18 reveals that the median iF for existing central stations in California (n = 25) is 0.8 per million, with an interquartile range of a factor of 6 and a factor of 60 overall range. The median for existing cogeneration units is slightly lower, likely owing to their typically more sparsely populated locations. The median for existing DG (> 1 MW) is approximately 2 per million, which likely reflects the lower stack heights of these sources compared to central stations. The estimates of the ranges and medians for the cogeneration and DG (> 1 MW) units are less certain owing to the smaller number of cases compared to those for central stations. The variability in iF for central stations is greater than that for cogeneration and existing DG (< 1 MW) units because the number of cases is substantially greater.

Figure 19 shows that the difference between urban and rural existing central station and cogeneration units is about an order of magnitude, with existing DG (<1 MW) a factor of 4. The direction of this result is expected, owing to differences in population density downwind. Note that the divergence between urban and rural sources is found without controlling for all other differences between cases, such as release height and meteorology. Figure 19 also depicts an overlap in the ranges of iF for urban and rural

central station and cogeneration cases. [32] Our urban/rural designation reflects the US Census Bureau's, which is based only on the local population density. For some cases, it is likely that the Census Bureau's designation does not accurately reflect the population density of those exposed within our modeling domain of 100 km. In the future, one could consider employing a system of determining population density within a certain radius of a point source. This metric would be determined on a continuous, ratio scale rather than the current dichotomous designation. Such an approach would allow closer scrutiny of the relationship between intake fraction and proximate population density.

Figure 20 plots the annual-average effective stack height for all existing sources[33] against the annual-average iF. It is apparent from this chart that urban and rural cases have different characteristic intake fractions. A power law adequately describes each set of data, with slopes of approximately an order of magnitude decrease in iF for every order of magnitude increase in annual-average effective stack height. For urban cases, the best-fit equation is $y = 285x^{-0.99}$ ($r^2 = 0.59$) for urban cases, while for rural cases it is $y = 30x^{-0.92}$ ($r^2 = 0.36$). The overlap in range of iF observed in Figure 19 between urban and rural cases is also apparent in Figure 20. The rural cases with iFs similar to urban ones are all located adjacent to highly urbanized areas (Pebbly Beach (two stacks), Ormond Beach (two stacks) and Contra Costa (one stack)). The reverse is true for an urban case with iFs more characteristic of rural sites (Monterey Regional WPCA (2 stacks)). Whereas designating a source as urban or rural based on local population density may be appropriate for some parametrizations for which we use this designation (e.g., adjusting wind speed to determine the effective stack height), with regards to intake fraction, it appears to lead to some misclassification, which blurs the distinction between these two location categories.

One might expect the intake fraction of an existing unit to be related to its capacity. This could be true if plant capacity were related to effective stack height, for instance, or if larger plants were more often located in areas further away from population centers. While a slight decreasing trend for intake fraction with increasing capacity can be seen in Figure 21, this relationship is weak; capacity only explains 12% of the variation observed in intake fraction ($r^2 = 0.12$ for a power-law fit).

[32] The existing DG (> 1 MW) category does not exhibit overlap between urban and rural cases, likely owing to the small number of cases.
[33] Recall that a single source can have multiple stacks.

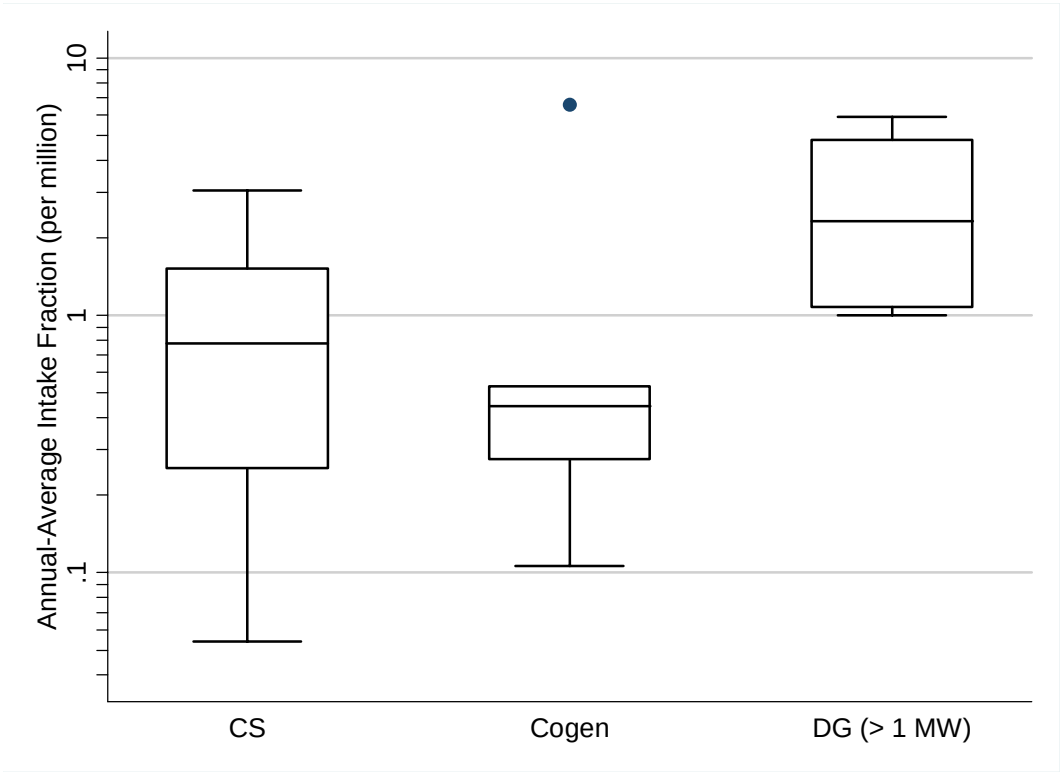

Figure 18. Interquartile box plots of conserved pollutant, annual-average intake fraction for the three types of existing electricity generation sources (n(CS) = 25, n(cogen) = 6, n(DG) = 6). (See Figure 9 caption for interpretation of the interquartile box plot.)

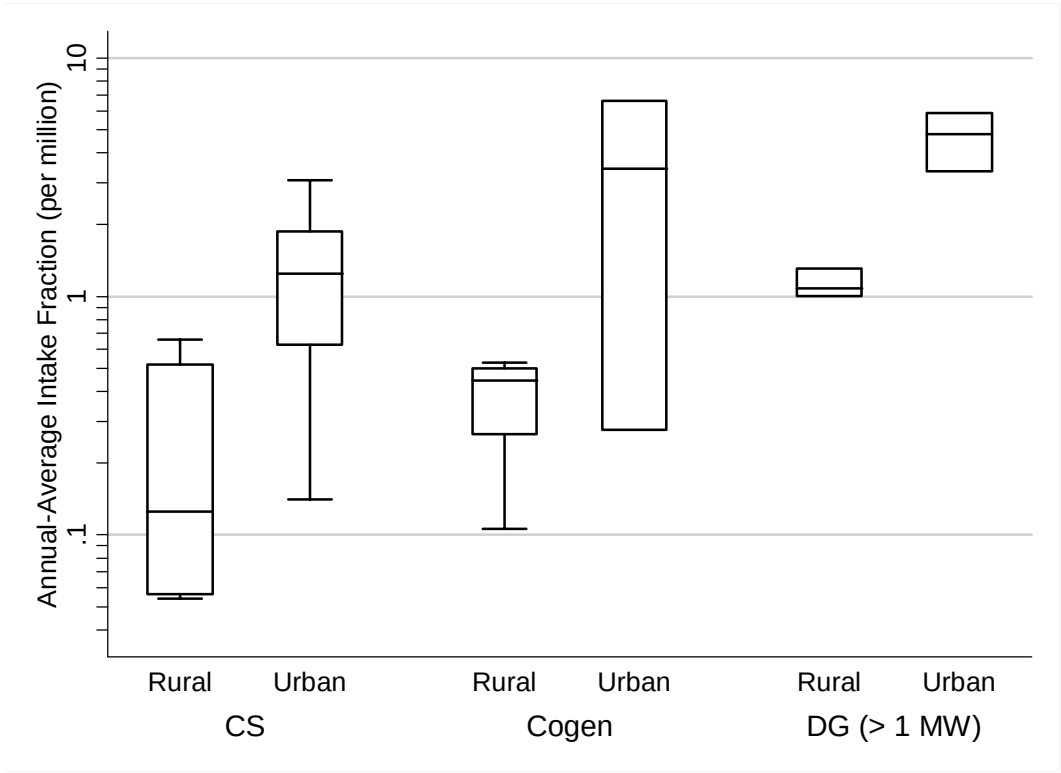

Figure 19. Interquartile box plots of conserved pollutant, annual-average intake fraction by location category for the three types of existing electricity generation sources (central station, cogeneration and existing DG) (n(CS, rural) = 7; n(CS, urban) = 18; n(cogen, rural) = 4; n(cogen, urban) = 2; n(DG, rural) = 3; n(DG, urban) = 3) (See Figure 9 caption for interpretation of the interquartile box plot.)

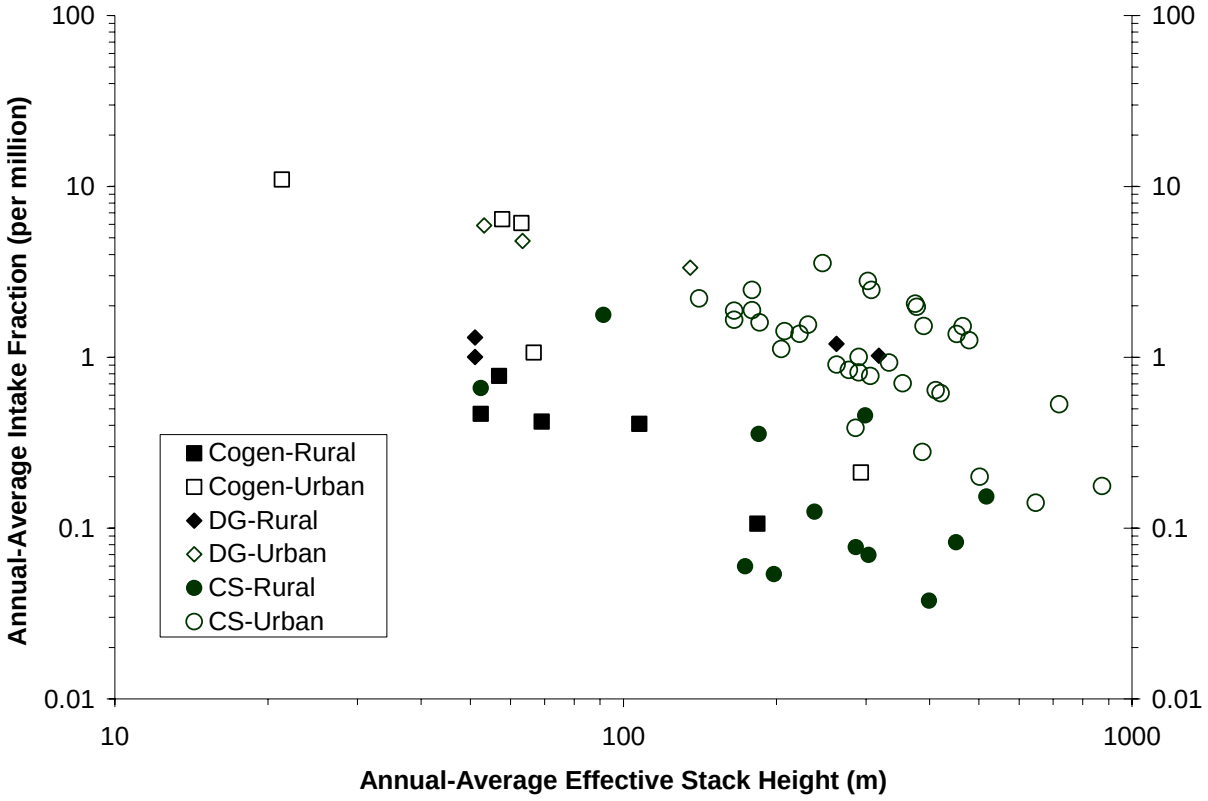

Figure 20. Annual-average conserved pollutant intake fraction, per stack, versus annual-average effective stack height (m), by plant type (all three categories of existing sources, CS = circles, Cogen = squares, DG (> 1 MW) = diamonds) and location category (urban = unfilled, rural = filled). In total, there are 64 stacks for the 37 existing units assessed.

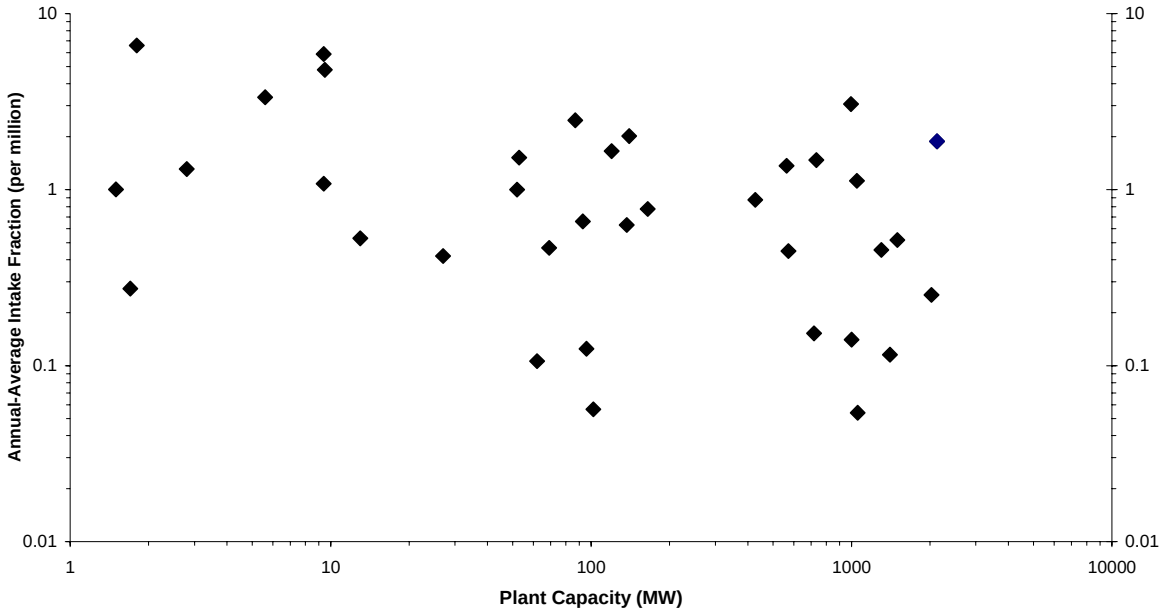

Figure 21. Annual-average conserved pollutant intake fraction versus plant capacity for all existing plants (central station, cogeneration and existing DG (> 1 MW)).

III.A.1.b Hypothetical DG Cases

Figure 22 displays the annual-average intake fraction for hypothetical DG cases. Intake fractions for hypothetical DG units located in the downtown core are greater – but only by approximately a factor of two – than those co-located at central station sites. This difference might not be as large as one might have expected if one assumed that central stations are not located in urban areas or, as in some cases, in the urban core. In California, a substantial portion of the existing stock of power plants is located in urban areas. As in the plot for the existing units, the central tendency for intake fraction for co-located cogeneration stations is lower than for those co-located at either existing central stations or DG (> 1 MW) plants. Interestingly, the median annual-average iF is approximately the same for hypothetical DG units co-located at the sites of existing DG (> 1 MW) plants as for those co-located at central station sites. Because all hypothetical DG units are assumed to have the same effective stack height, this result reveals that the existing DG (> 1 MW) units we selected are of similar proximity to urban areas as the central stations, in central tendency at least (note the range for central stations is quite large and has a long lower tail).

The difference in intake fraction between those hypothetical DG (< 1 MW) units located in rural areas to those in urban ones (Figure 23) is approximately a factor of 5, 3 and 2.5 for cogeneration, central station and existing DG (< 1 MW) sites, respectively. Hypothetical DG units located at central station and existing DG (> 1 MW) sites display a lesser difference than what was observed for existing units in Figure 19 (i.e., a factor of ten). One possible reason for urban and rural intake fractions to be more similar for the shorter stacked, small-scale DG units is the blurring of the distinction between the urban/rural designation. We have previously pointed out that three plants (two central stations (Ormond Beach and Contra Costa) and one existing DG (> 1 MW) (Pebbly Beach)), while designated as rural, are actually adjacent to large population centers. Since short stacks emphasize near-source population exposure, we would expect the intake fraction from each of these sources to be more similar to a unit located in an urban area.

Figures 24 and 25 display the intake fractions for all urban and rural sources (both those co-located at the sites of existing units as well as those located at city halls), respectively. With effective stack heights identical between cases, intake fractions vary between sites primarily according to the population density within 100 km of the source. Our preliminary research on this topic (Heath *et al.*, 2003) found that varying meteorology did not impact the annual-average iF as significantly as either population density or stack height.

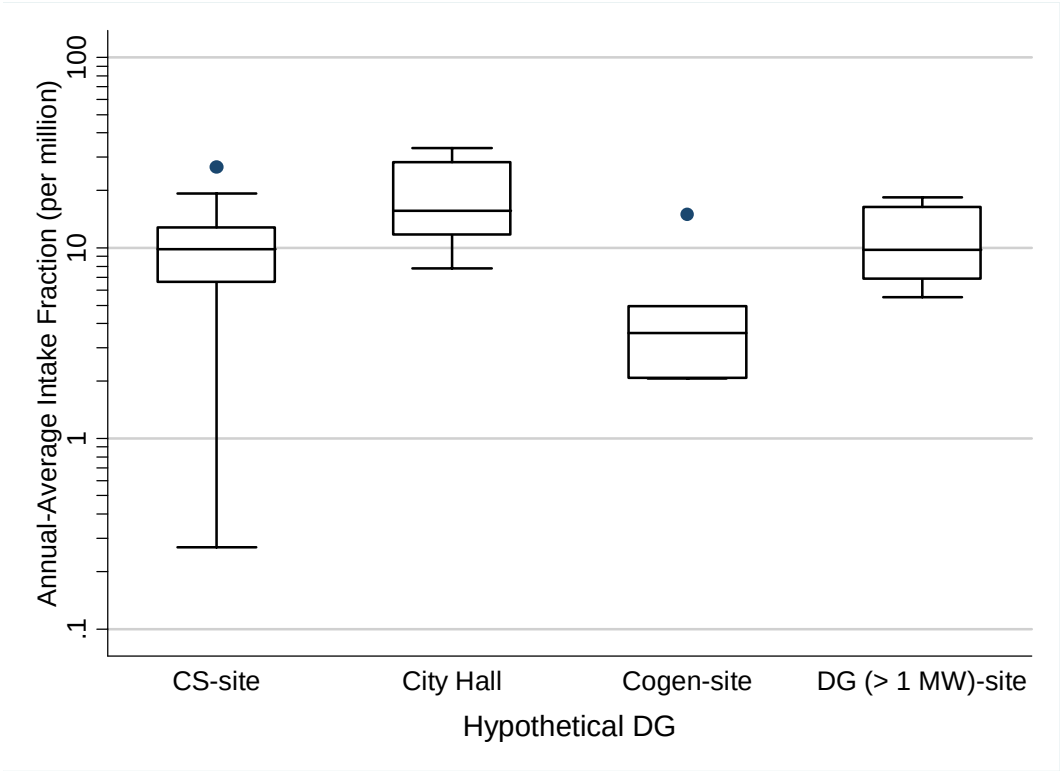

Figure 22. Interquartile box plots of conserved pollutant, annual-average intake fraction for hypothetical DG sources co-located at the sites of the three categories of existing source cases (n(CS) = 25, n(cogen) = 6, n(DG) = 6) as well as at the city halls of the eleven most populous cities in California (n = 11). All hypothetical DG sources have a constant effective stack height of 5 m. (See Figure 9 caption for interpretation of the interquartile box plot.)

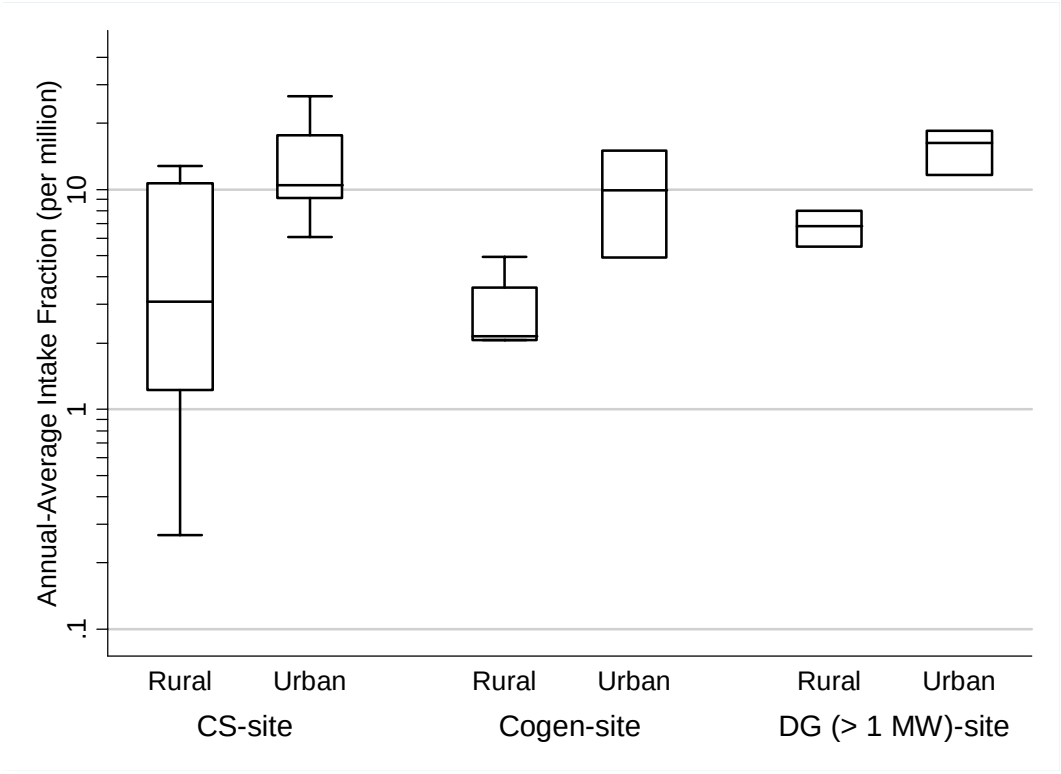

Figure 23. Interquartile box plots of conserved pollutant, annual-average intake fraction for each type of co-located hypothetical DG source by location category (n(CS-site, rural) = 7, n(CS-site, urban) = 18, n(cogen-site, rural) = 4, n(cogen-site, urban) = 2, n(DG, rural) = 3, n(DG, urban) = 3). All hypothetical DG sources have a constant effective stack height of 5 m. (See Figure 9 caption for interpretation of the interquartile box plot.)

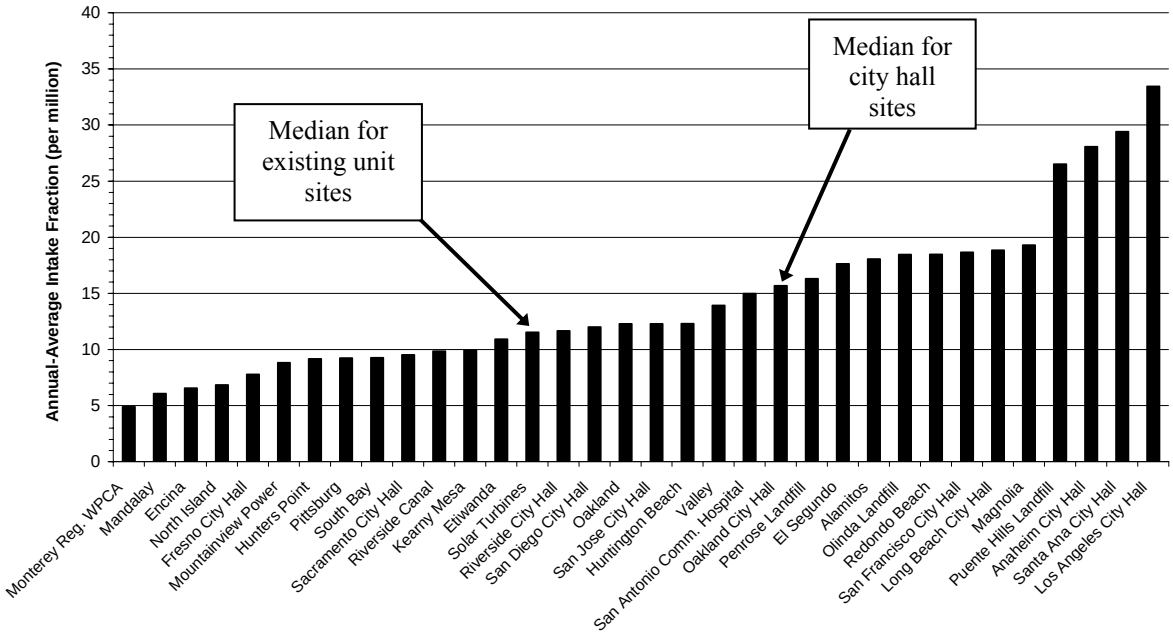

Figure 24. Annual-average conserved pollutant intake fraction for urban hypothetical DG units (n = 34), both co-located with existing sources and sited at the city halls of the eleven most populous cities in California, sorted by annual-average iF. The effective stack height for all hypothetical DG units is assumed a constant 5 m.

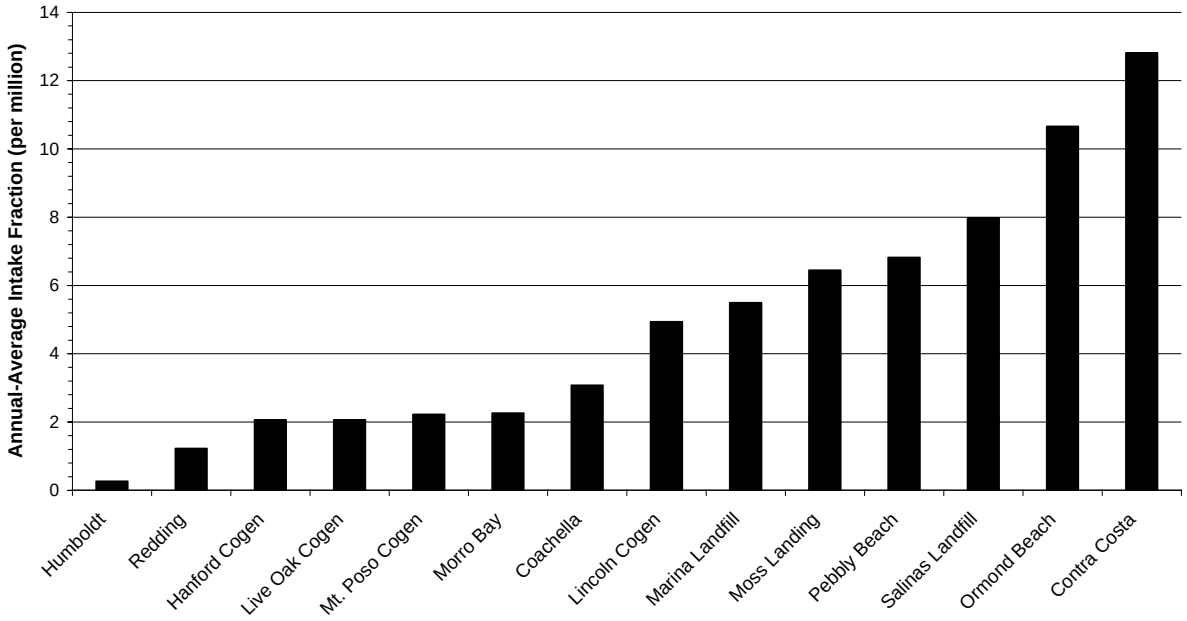

Figure 25. Annual-average conserved pollutant intake fraction for rural, hypothetical DG units located at the sites of all rural existing plants of all types (n = 14), sorted by iF. The effective stack height for all hypothetical DG units is assumed a constant 5 m.

III.A.1.c Comparisons Between Existing Units and Hypothetical DG Cases

Figure 26 compares the annual-average iF for the three types of existing units and co-located hypothetical DG units. As the population downwind and the meteorology are the same within pairs of co-located units, the affect of decreasing effective stack height to ground level (5 m) is revealed. The difference is approximately an order of magnitude between pairs of existing and hypothetical DG units at both central station sites (whose annual-average effective stack heights are typically hundreds of meters) and cogeneration sites (with annual-average effective stack heights near 100 m). Recalling the three key influences on iF, lowering the stack height increases proximity by decreasing the (vertical) distance between the source and receptors. The result is higher ground-level concentrations in the downwind region per unit mass emitted and, consequently, higher intake. For the existing DG (> 1 MW) sites, the difference is less – a factor of 4. While their annual-average stack heights are only slightly greater than those for cogeneration plants, this divergent result could be related to differences in the proximity to and density of nearby population centers.

Figure 26 also reveals that the variability in iF within case types (as expressed by the range) is greater than the variability between types, for both existing units and hypothetical DG cases.

Figure 27 examines the relationship between intake fraction and release height for individual pairs of units co-located at central station sites. The chart separately plots the four combinations of modeling designations for the existing central stations. For urban sources (both elevated and ground-based), the range of difference between location pairs is from less than one order of magnitude to nearly two. The same range of differences is found for central stations located in rural areas. It should be noted that in modeling, we designated stacks as either elevated or ground-based, not plants. For display purposes, Figures 28-29 assign a similar designation to the entire plant based on the level at which a majority of pollutant volume is emitted.

Figure 28 and 29 are similar to Figure 27 except the type of existing unit is cogeneration and DG (> 1 MW), respectively. A similar difference in intake fraction is observed between these co-located pairs of existing and hypothetical DG units.

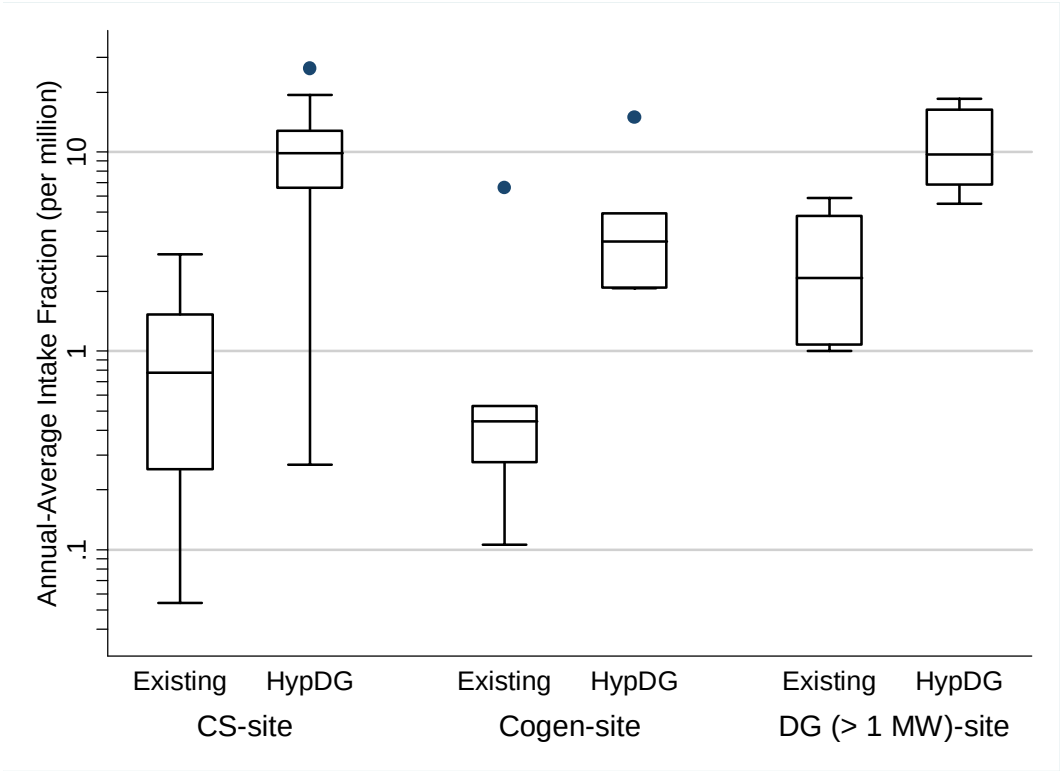

Figure 26. Interquartile box plots of conserved pollutant, annual-average intake fraction for existing sources (existing) compared to co-located hypothetical DG (HypDG) sources within each of three categories of cases (n(CS) = 25, n(cogen) = 6 and n(DG) = 6). This plot displays the differences in distributions of intake fraction (per million) for sources of non-negligible effective stack height (existing sources) compared to those with a constant effective stack height of 5 m, given the same meteorology and population distribution within 100 km. (See Figure 9 caption for interpretation of the interquartile box plot.)

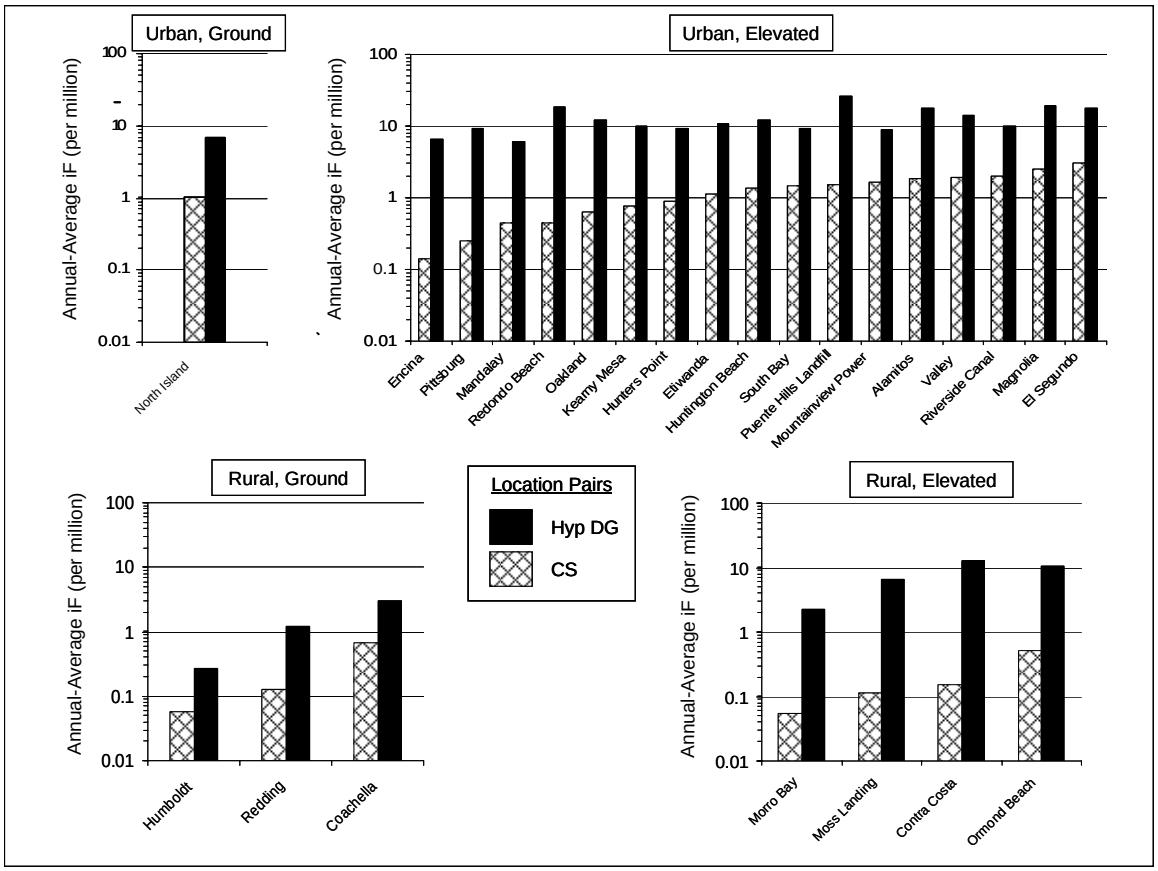

Figure 27. Comparison of annual-average conserved pollutant intake fractions for central stations and co-located hypothetical DG units (Hyp DG) by location category (urban/rural) and release type (elevated/ground). The only difference within a location pair is the effective stack height, which is assumed to be a constant of 5 m for all hypothetical DG cases and is calculated hourly for all existing sources. There is one urban, ground-level central station location pair; 17 urban, elevated pairs; three rural, ground-level pairs; and four rural, elevated pairs.

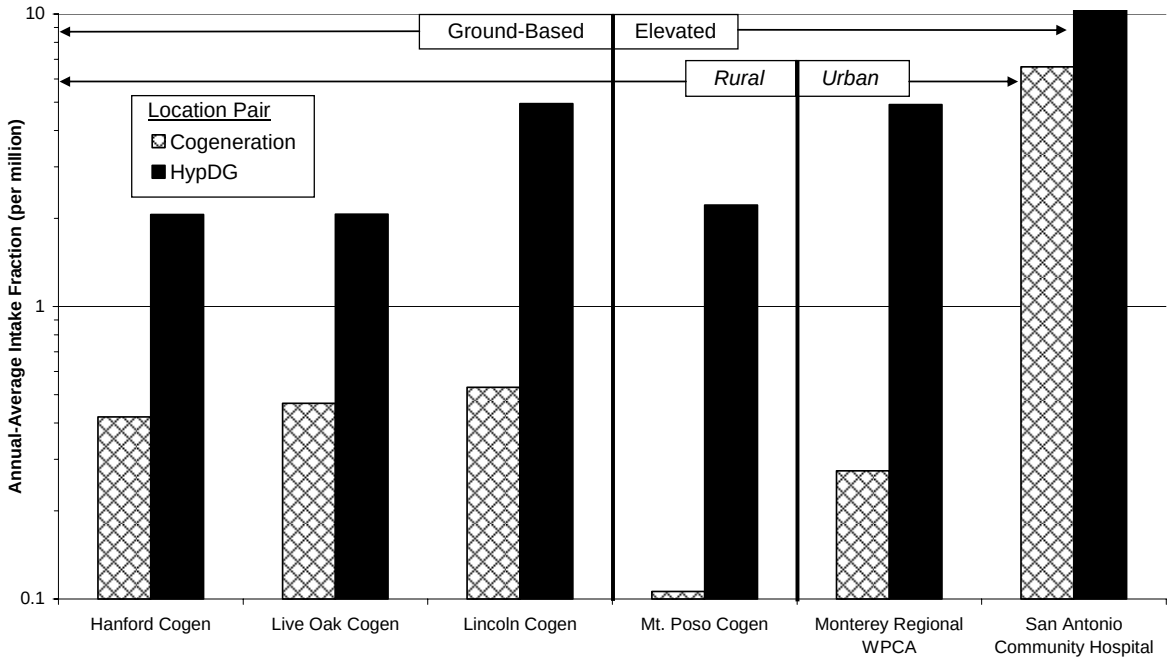

Figure 28. Annual-average conserved pollutant intake fraction for pairs of existing cogeneration stations and co-located, hypothetical DG units (Hyp DG) by location category (urban/rural) and release type (elevated/ground). The only difference within a location pair is the effective stack height, which is assumed constant at 5 m for hypothetical DG cases and is calculated hourly for existing sources.

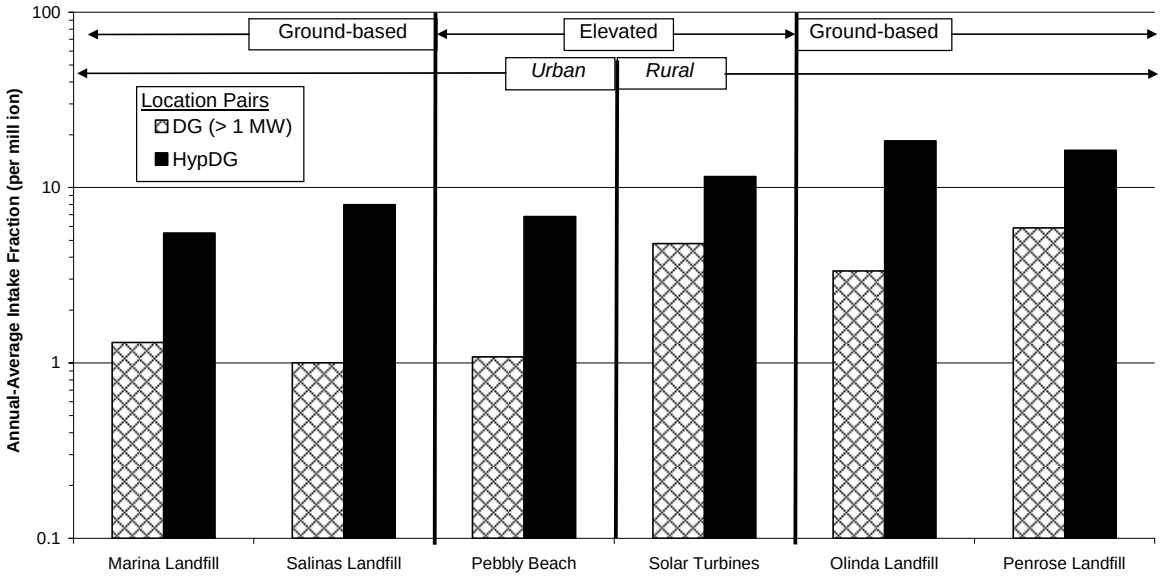

Figure 29. Annual-average conserved pollutant intake fraction for pairs of existing DG (> 1 MW) and co-located, hypothetical DG units by location category (urban/rural) and release type (elevated/ground). The only difference within a location pair is the effective stack height, which is assumed constant at 5 m for hypothetical DG cases and is calculated hourly for existing sources.

III.A.2 Results for Decaying Pollutant

Figure 30 compares the annual-average intake fraction for conserved pollutants to that for a primary decaying pollutant, formaldehyde. The distributions incorporate all existing units (central station, cogeneration and DG (> 1 MW)). The iF for primary formaldehyde is, in central tendency, approximately 80% of the iF for primary conserved pollutants. It also should be noted that the variability within each class of pollutant is far greater than the variability between the classes.

Figure 31 compares, for primary formaldehyde, annual-average intake fraction for existing units and co-located hypothetical DG units. Primary formaldehyde's decay dampens the differences between each location pair compared to the differences shown in Figure 26 for a conserved pollutant. All other comparisons within the results for primary formaldehyde (urban/rural, elevated/ground, co-located hypothetical DG units vs. ones at city halls) have similar results as for the primary conserved pollutant.

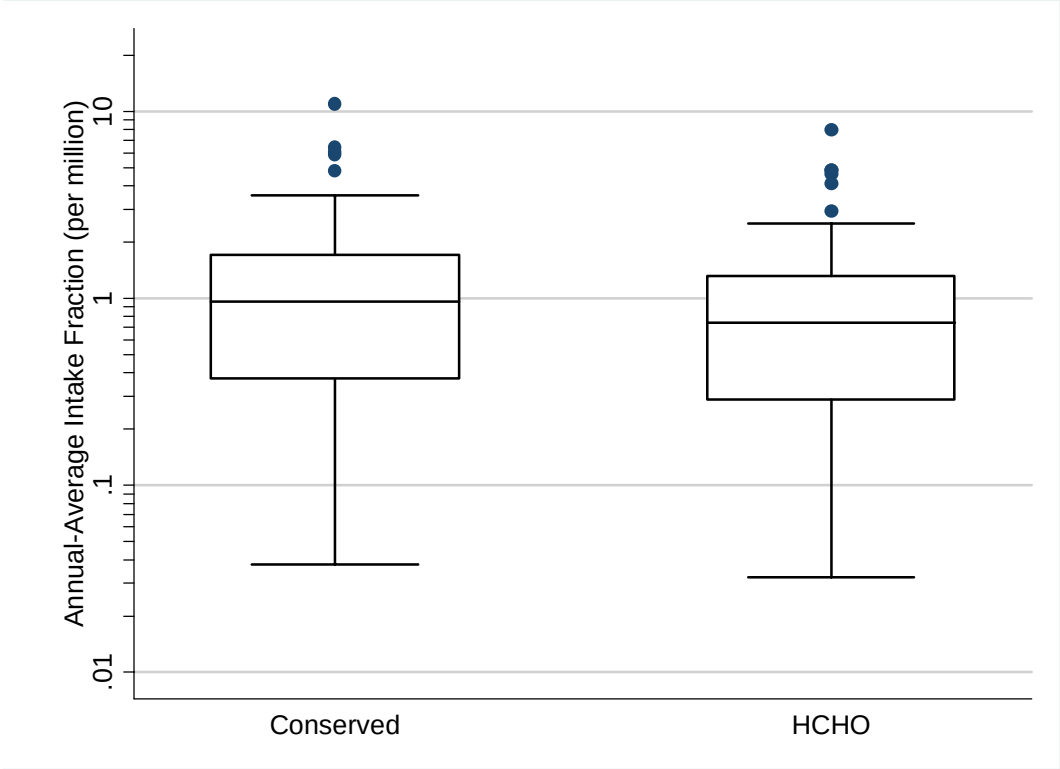

Figure 30. Interquartile box plots of annual-average intake fraction for a primary conserved pollutant and a decaying pollutant (primary formaldehyde) considering all case types (CS, cogen, existing DG; for each pollutant, n = 37). (See Figure 9 caption for interpretation of the interquartile box plot.)

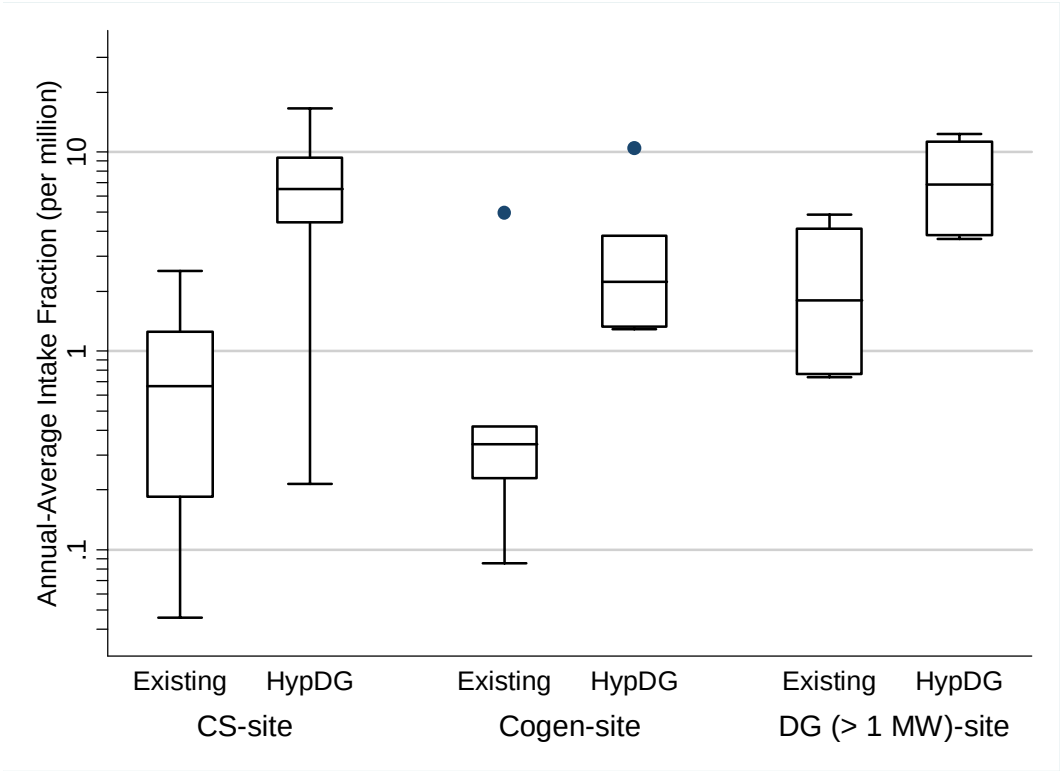

Figure 31. Interquartile box plots of decaying pollutant (primary HCHO), annual-average intake fraction for co-located existing sources (Existing) vs. hypothetical DG (HypDG) sources within each of three categories of cases (n(CS) = 25, n(cogen) = 6 and n(DG) = 6). This plot displays the differences in distributions of intake fraction (per million) for sources of non-negligible effective stack height (existing sources) compared to those with a constant effective stack height of 5 m, given the same meteorology and population distribution within 100 km. (See Figure 9 caption for interpretation of the interquartile box plot.)

III.A.3 Comparison to Previous Research

Other researchers have assessed the intake fraction for pollutants emitted from large point sources, such as power plants (Smith, 1993; Lai *et al.*, 2000; Nigge, 2001; Evans *et al.*, 2002; Levy *et al.*, 2002a; Levy *et al.*, 2003; Li and Hao, 2003; Zhou *et al.*, 2003). The results of these studies are summarized in Table 19 (reporting estimated intake fraction values) and Table 20 (highlighting differences in method and key parameters). To allow for direct comparisons of intake fraction, these values are adjusted, where necessary, to the population-average breathing rate of 12 m^3/d used in this study.

Comparing our results for a conserved species to those of Nigge (2001) and to those for primary PM, we find broad agreement. In cases where conserved or primary PM iF estimates are considerably higher than our estimate (Smith's for the less developed country as well as those for China and Thailand), the different average population density provides a probable explanation. It is likely that Phonboon's iF is higher also because of the "relatively low stack height" of the source (Evans *et al*., 2002), yielding close vertical proximity between source and receptors. We can account for differences between our estimates and the other studies based in the US with the following observations. First, all of the US-based studies assume a decay rate for primary PM. Additionally, while some specific sources in those studies are located in urban areas, most are located in rural zones whose population density is lower than that typical of California. These two observations would tend to reduce population iF, all other factors being equal, compared to ours. On the other hand, the modeling domains of all other US-based studies are considerably greater than ours. This would tend to increase population iF as more people's exposure is considered. This final comment might help explain Wolff's (2000) higher population iF result.

Some studies have noted that a modeling domain even of 500 km surrounding a point source is not adequate to capture population inhalation intake fully. This is particularly true for secondary species, which we do not assess in this study. It is also true for those areas of the country that have higher rural population densities (like the Southeastern and Midwestern parts of the US) and more numerous and spatially frequent cities than the settlement patterns of the western part of the US. Thus, we do not expect intake fractions from sources in California to increase substantially if we were to expand our modeling domain.

In sum, we find broad agreement with the results of previous intake fraction studies on similar sources to ones we assess. A novel contribution of our study is the quantitative exploration of differences in population inhalation intake between the two paradigms of electricity generation: central station and distributed generation. Previous research has shown that differences in effective stack height are an important factor influencing intake fraction (Lai *et al.*, 2000; Nigge, 2001; Levy *et al.,* 2002b). Our research both extends this result to stack heights appropriate to distributed generation and confirms the more generic sensitivity analyses of Lai *et al.* (2000) and Nigge (2001) through a series of case studies. In addition, our work addresses hazardous air pollutants which have not been studied thus far, as well as focusing on California, a coastal state with considerably different meteorology and population distribution than previous study locations.

Table 19. Comparison of present results with other published values of intake fraction for large point sources (mainly power plants). (See also Table 20 for descriptions of the design of each of these studies.)

CITATION	INTAKE FRACTION[a] (per million)				
	Conserved	Primary PM[b]	Secondary PM		Decaying
			Sulfate	Nitrate	
Smith, 1993[c] (USA)		0.4 (0.07 - 1.4)			
Smith, 1993[c] (least developed country)		4 (0.6 - 13)			
Phonboon, 1996[d]	54 (Benzene)[e]	18			18 (SO_2)
Wolff, 2000[d]		1.3 (0.15 - 3.8)	0.10 (0.04 - 0.13)	0.016 (0.0044 - 0.035)	
Nigge, 2001	1.8 - 3				
Levy *et al.,* 2002a		0.6 (0.4 - 2.4)	0.12 (0.06 - 0.18)	0.18 (0.12 - 0.30)	
Levy *et al.* , 2003		0.4 (0.3 - 0.6)	0..096 (0.09 - 0.10)	0.038 (0.035 - 0.043)	
Zhou *et al* ., 2003		9 (5.4 - 15)	3.6 (1.8 - 6.6)	3.9 (1.2 - 9.0)	5.0 (SO_2) (3.0 - 7.8)
Li and Hao, 2003		9.5 (5.2 - 190)	1.4 (0.96 - 1.8)	1.5 (0.96 - 2.0)	
current study (all central station cases)	0.78 (0.054 - 3.1)				0.66 (HCHO) (0.046 - 2.5)
current study (urban central station cases)	1.2 (0.14 - 3.1)				1.0 (HCHO) (0.11 - 2.5)
current study (rural central station cases)	0.12 (0.054 - 0.66)				0.11 (HCHO) (0.046 - 0.56)

[a] Central estimate is the arithmetic average, with the min/max range (when reported) in parentheses. All values are adjusted to a breathing rate of 12 m^3/d.

[b] A decay rate is assumed in each study for primary PM.

[c] As reported in Smith, 1993 and Evans *et al.,* 2002.

[d] As reported in Evans *et al* ., 2002. Breathing rate for original values in Wolff (2000) assumed to be 20 m^3/d.

[e] While a decay rate is used for benzene, it is so slow that this pollutant can be considered as a conserved species.

Table 20. Brief description of the models and key parameter values of each of the intake fraction studies cited in Table 19.

Citation	Number of Point Sources Assessed	Stack Height(s) (m)	Urban / Rural[a]	Country / State	Average Population Density (per km^2)	Dispersion Model	Modeling Domain / Distance Downwind	Grid Cell Size	Comments
Smith, 1993[b]	86		Rural	USA	30	Pacific Northwest Laboratory long-range transport model	USA		based on Rowe (1981) study of hypothetical, 1000 MW coal-fired power plants; particle size not specified.
Smith, 1993[b]	generic			typical LDC	270	-			applied higher population density of least developed countries (LDC) to USA results.
Phonboon, 1996[c]	1		Urban	Thailand	923	ISCLT2	100 km		Bangkok oil refinery emissions with relatively low stack height; iFs did not increase significantly beyond 50 km because population density much lower and relatively short half-life of pollutants.
Wolff, 2000[c]	40		Both	USA & bordering Canada & Mexico	30[d]	CALPUFF	1600 x 2800 km	100 x 100 km	coal-fired plants; primary $PM_{2.5}$.
Nigge, 2001	generic	200[e]	Both	Germany	70 - 1600	Gaussian	100 km		tested sensitivity parametrically to population densities characteristic of various settlement classes as well as various effective stack heights.
Levy *et al.,* 2002a	9	84 - 168	Both	Illinois	55	CALPUFF	750 x 750 km	15 x 15 km (met.); census tract (pop. & conc.)	coal-fired power plants near Chicago, IL; full year simulation (1999); primary $PM_{2.5}$.
Levy *et al.*, 2003	7	250 - 500[e]	Both	Georgia	50[f]	CALPUFF	500 km	250 x 250 km (met.); census tract (pop. & conc.)	coal-fired plants near Atlanta, GA; used projected 2007 population; primary $PM_{2.5}$ results from CALPUFF are within 10% of those for source-receptor (S-R) matrix over same domain and 70% of the S-R-derived value for a domain of the continental US.
Zhou *et al*., 2003	1	210	Urban	China	180	CALPUFF	3360 x 3360 km	60 x 60 km (met.); 28 x 28 km (pop. & conc.)	iFs were computed as the average of 10-day episodes in each of 4 seasons in 1995; primary $PM_{2.5}$.
Li and Hao, 2003	17	25-240	Both	Hunan province, China	135 - 1770	CALPUFF	500 km	40 x 40 km (met.); radial receptor grid (r = 1 km near source, 50 km beyond 200 km from source)	primary $PM_{2.5}$.
current study (central station cases)	25	52 - 1010[e]	Both	California & bordering Mexico	85	Gaussian	100 km	radial receptors at 0.5 km increments; census tract (pop.)	annual-average iF based on an hourly, annual cycle of typical meteorological conditions; n(urban) = 18; n(rural) = 7.

[a] This is a description of the character of the population density in the vicinity of the source(s).

[b] As reported in Smith, 1993 and Evans *et al.*, 2002.

[c] As reported in Evans *et al*., 2002.

[d] US population density estimated based on average of 1990 and 2001 population density (US Census, 2003).

[e] Values reported are effective stack heights (m).

[f] Georgia population density estimated based on average of 1990 and 2001 population and Georgia land area (US Census, 2003).

III.B Intake-to-Generation Ratio Results

The intake-to-generation ratio represents the mass of emitted pollutant inhaled by the downwind population per unit of electricity delivered. It is an intake fraction normalized by a pollutant- and technology-specific emission factor. The goal in this section of the report is two-fold. First, we estimate intake-to-generation ratios for both primary $PM_{2.5}$ and formaldehyde for two types of existing units: central stations and DG (> 1 MW). [34] Figure 32 compares IGRs of the two types of existing units for primary $PM_{2.5}$; Figures 33-35 explore differences within existing central stations across the two modeling designations (urban/rural and elevated/ground) and fuel types. Results for formaldehyde are reported only in the summary tables (section III.D) because the direction and magnitude of all comparisons examined are nearly identical to those found for primary $PM_{2.5}$.

We also estimate both primary $PM_{2.5}$ and formaldehyde IGRs for the five hypothetical DG technologies in addition to hypothetical, BACT-controlled, existing units. [35] We focus on the comparison of central stations (existing and BACT-controlled) to small-scale DG sited in downtown urban areas to emphasize the potential impact of shifting the scale of electricity generation towards increased reliance on DG. IGRs for DG technologies co-located at the sites of the central stations and existing DG (> 1 MW) units are listed in Tables 23 and 24.

III.B.1 Existing Unit IGRs

Figure 32 displays the primary $PM_{2.5}$ IGRs for existing central stations and DG (> 1 MW) units. The higher emission factor and intake fractions of the DG (> 1 MW) plants compound to result in a factor of 20 difference in medians between the two types of existing units. Variability is greater for central stations due to the greater number of cases. Figure 33 reveals for urban existing central stations have an order of magnitude greater primary $PM_{2.5}$ IGR than rural ones. Urban and rural ground-based central stations have greater primary $PM_{2.5}$ IGR than ones with elevated releases (Figure 34). [36] The smaller multiple for rural elevated releases is probably a result of the relatively high stack height used to classify rural cases. We will parametrically investigate the uncertainty associated with our designation strategy in future work. Finally, with central stations and existing DG (> 1 MW) units considered together, those that burn oil as the primary fuel[37]

[34] Recall that owing to uncertainty in emissions, we did not calculate emission factors and, by extension, the IGR, for the cogeneration stations.

[35] Assuming similar stack characteristics, iFs for BACT-controlled existing units are the same as for the existing units themselves. IGRs are the product of the BACT emission factor and the existing unit iF.

[36] This figure considers a plant "elevated" if the majority of volumetric flow is released from elevated stacks, and vice versa for a "ground-based" designation. The reason we categorized plants by release type for this analysis, in contrast to the intake fraction modeling designation of release type that was determined per stack, was to be consistent with the emission factor being an attribute of the plant.

[37] The analysis that produced Figure 35 considers only the majority fuel, whereas some plants burn multiple fuels. Thus, there is not as clean a distinction between these categories as the nomenclature would suggest. Consequently, one would expect blurring of the expected distinction in both emission factors and IGRs.

have a factor of 40 greater primary $PM_{2.5}$ IGR than those burning either natural gas or landfill gas (LFG) (Figure 35). While the central tendencies of the natural gas- and LFG-burning units is nearly equal, the distribution for natural gas units is skewed to lower primary $PM_{2.5}$ IGRs. Caution should be used in interpreting the results of Figure 35 since the results for oil- and LFG-burning units are based on a small sample of three each, compared to 25 natural gas-burning existing units.

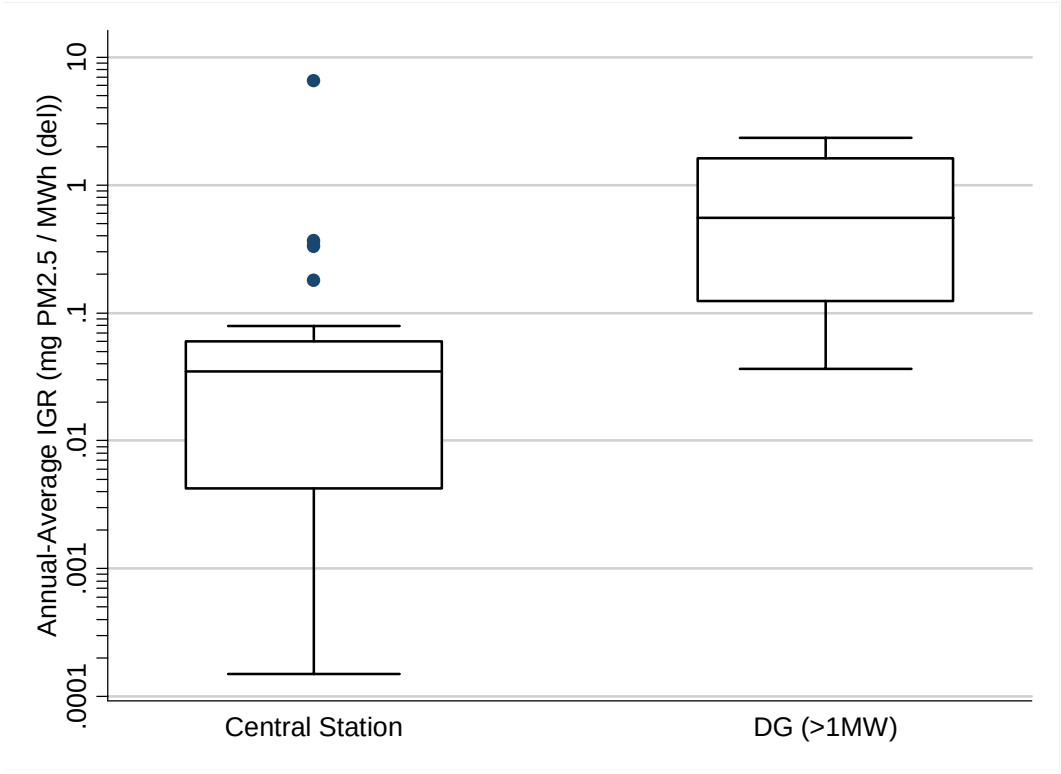

Figure 32. Interquartile box plots of annual-average IGR for primary $PM_{2.5}$ for two types of existing electricity generation sources (n(CS) = 25, n(DG) = 4). The six cogeneration stations are not included owing to uncertainty in emissions. In addition, two existing DG sources did not report PM emissions and so are not included here. (See Figure 9 caption for interpretation of the interquartile box plot.)

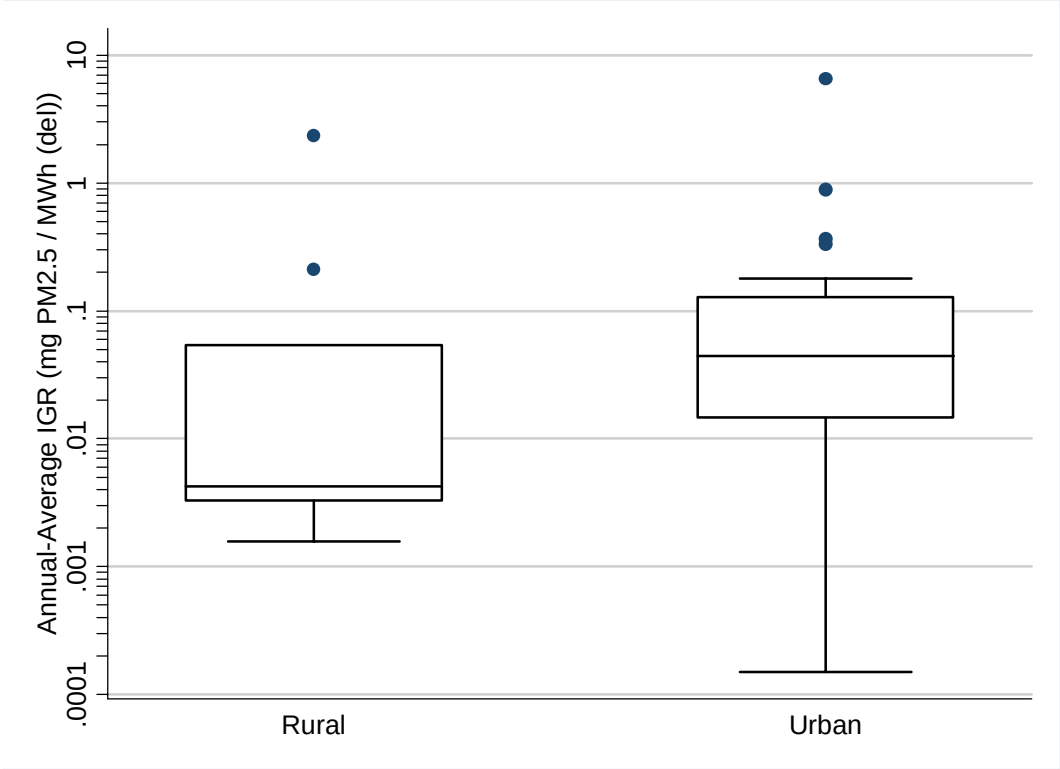

Figure 33. Interquartile box plots of annual-average IGR for primary $PM_{2.5}$ by location category (n(urban) = 18, n(rural) = 7) for central stations. (See Figure 9 caption for interpretation of the interquartile box plot.)

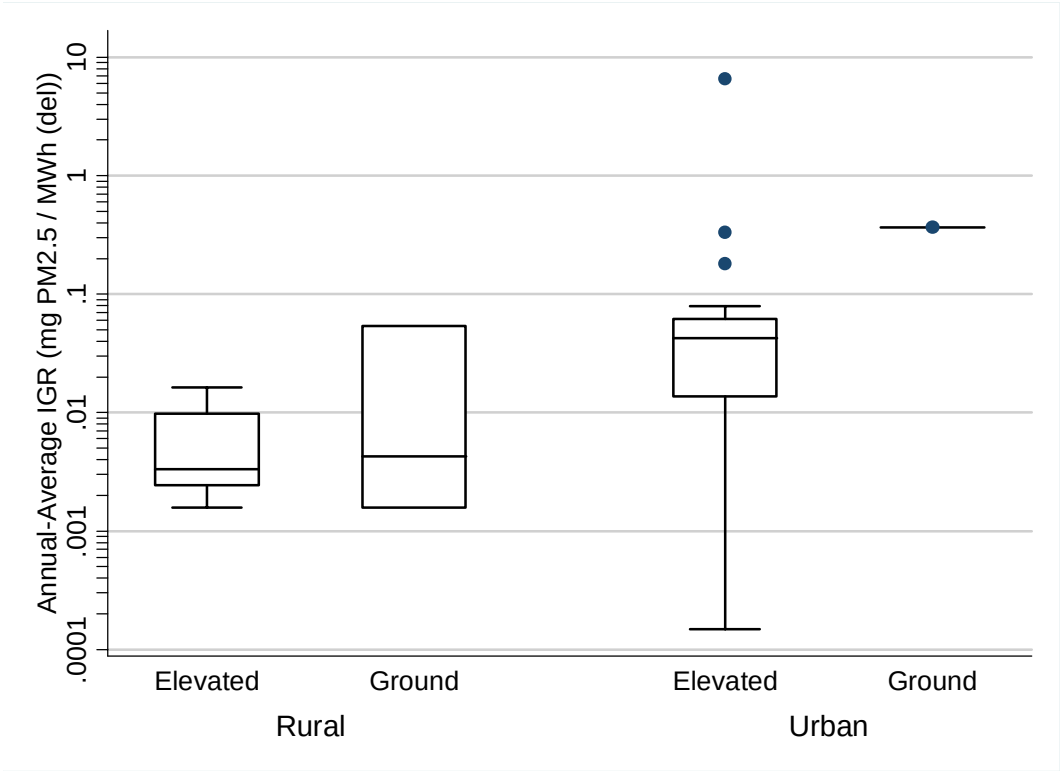

Figure 34. Interquartile box plots of annual-average IGR of primary $PM_{2.5}$ by release type and location category (n(rural, elevated) = 4, n(rural, ground) = 3, n(urban, elevated) = 17, n(urban, ground) = 1) for central stations. (For this analysis, release type was determined by plant. See the text discussion of this figure for further explanation.) (See Figure 9 caption for interpretation of the interquartile box plot.)

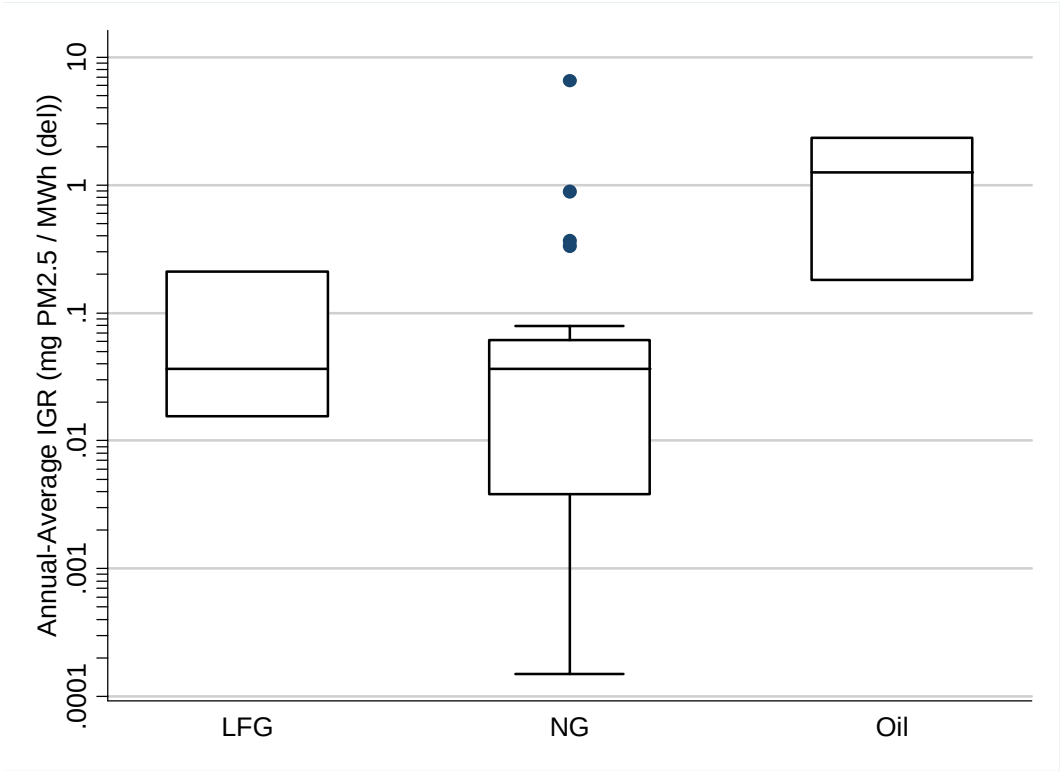

Figure 35. Interquartile box plots of annual-average IGR of primary $PM_{2.5}$ by fuel type (n(NG) = 25, n(landfill gas (LFG)) = 3, n(oil) = 3) for two types of existing electricity generation sources (central station and existing DG (> 1 MW)). The six cogeneration stations are not included in this analysis owing to uncertainty in emissions. Two existing sources (both LFG) did not report PM emissions and so are not included here. (See Figure 9 caption for interpretation of the interquartile box plot.)

III.B.2 IGRs for Small-Scale DG Technologies (< 1 MW) and BACT-Controlled Existing Units Compared to the Existing Units

To highlight the potential exposure impact of shifting from a centralized electricity generation system to a one with substantial DG in urban areas, Figures 36 and 37 compare primary $PM_{2.5}$ and formaldehyde intake-to-generation ratios, respectively, for five small-scale (< 1 MW) DG technologies located at eleven California city halls to both the central stations themselves and hypothetical, BACT-controlled central stations. For even the cleanest-burning, new DG technologies (microturbines and fuel cells) sited in the urban core, the central tendency of IGR is greater by at least an order of magnitude (for $PM_{2.5}$) or two (for HCHO) than existing central stations. For the other DG technologies that are more widely used in the existing stock (ICEs and turbines), IGRs can be as much as three orders of magnitude greater than our current system. Compared to hypothetically BACT-controlled existing units, urban DG IGRs are another factor of 4 (for $PM_{2.5}$) or 10 (for HCHO) larger. If the DG technologies were located at the sites of the existing central stations, IGRs would be reduced by approximately a factor of two owing to the lower average population density surrounding central station sites compared to the urban core (see Tables 23-25).

For both primary $PM_{2.5}$ and formaldehyde, while the median IGR for existing central stations is greater than if those units were BACT-controlled, there are some existing units with lower IGRs than even BACT-controlled units. The latter cases are at least outliers or possibly a result of erroneous reporting or compilation of emissions. Those plants that are likely outliers include Riverside Canal and Morro Bay for HCHO and Valley for primary $PM_{2.5}$, which correspond to the list of probable outliers considering emission factors. It is also worth calling out the likely outliers at the high end of the range. These are Magnolia for HCHO and primary $PM_{2.5}$, as well as Kearny for its HCHO IGR.

The median primary $PM_{2.5}$ emission factor for the existing units is very similar to those for the fuel cell, microturbine and NG turbines and, for formaldehyde, is within a factor of five of all small-scale DG technologies except the NG ICE (Figures 16 and 17). Thus, the differences between the existing unit's IGRs and those for the small-scale DG technologies (except the NG ICE) are due primarily to differences in intake fractions.

Because intake fractions are not a function of technology,[38] it is the differences in emission factors that cause the IGRs for small-scale DG technologies to be offset. Since the emission factors are point estimates, and thus contribute nothing to the distributional characteristics of the IGR, the distributions of IGR for each small-scale DG technology are identical. The hypothetical, BACT-controlled central stations also use a point estimate for emission factor, but their distribution is not identical to the small-scale DG technologies because their intake fractions reflect the greater variability of the existing units owing to differences in effective stack height. The IGRs for the existing units reflect both intake fraction and emission factor variability.

[38] Intake fractions are only dependent on location and effective stack height, the latter of which is constant at 5 m for all small-scale DG.

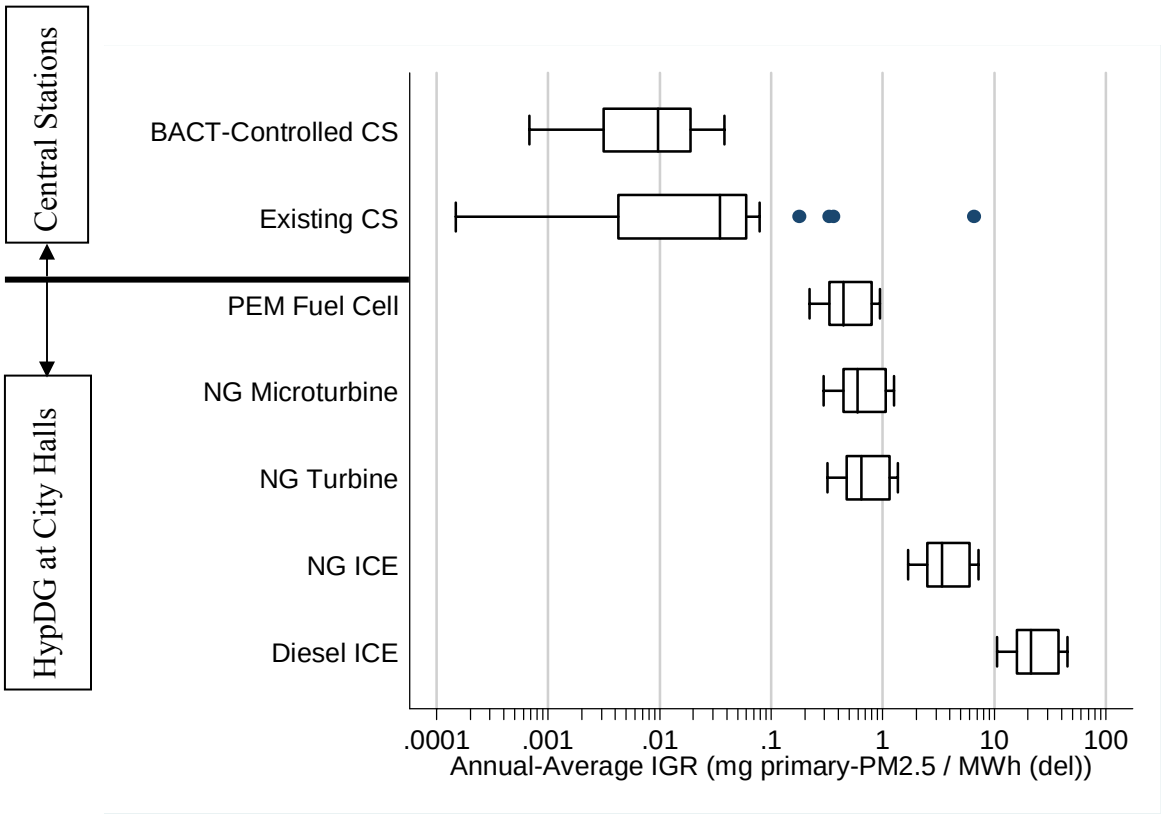

Figure 36. Interquartile box plots of annual-average IGR for primary $PM_{2.5}$ for existing and BACT-controlled central stations (n = 25) and DG technologies at city halls (n = 11). The BACT and existing categories use the intake fraction for the existing plant; the emission factor for BACT is taken from CARB guidance (CARB, 1999), whereas the emission factor for the real central stations is based on reported 1999 emissions related to electricity generation (EPA, 2003b). The intake fraction for all hypothetical DG technology cases is for a DG unit (< 1 MW) with a constant effective stack height of 5 m located at the city hall for California's eleven most populous cities; the emission factor for each technology is the best available in the existing literature (Samuelsen *et al*., 2003). (See Figure 9 caption for interpretation of the interquartile box plot.)

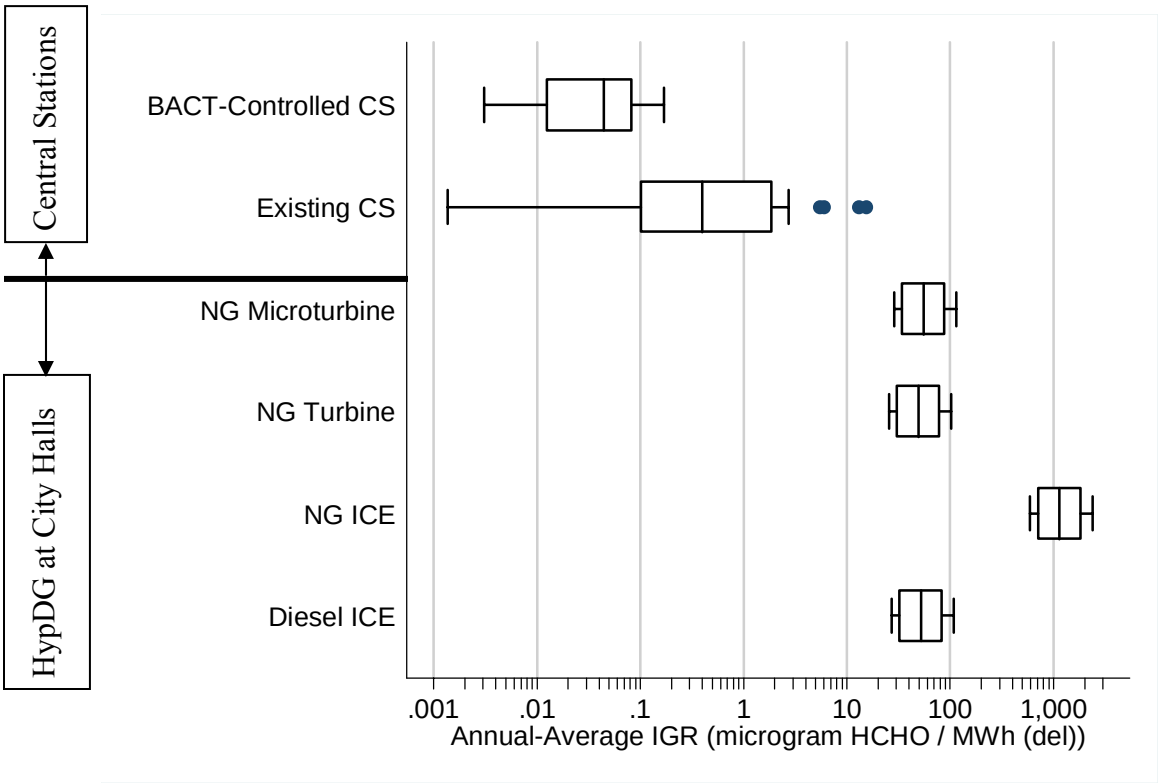

Figure 37. Interquartile box plots of annual-average IGR for primary HCHO for existing and BACT-controlled central stations (n = 25) and DG technologies at city halls (n = 11). The BACT and existing categories use the intake fraction for the existing plant; the emission factor for BACT is that for an SCR-controlled combined-cycle combustion turbine (EPA, 2000a), whereas the emission factor for the real central stations in the existing category is based on reported 1999 emissions related to electricity generation (EPA, 2003b). The intake fraction for all hypothetical DG technology cases is for a DG unit (< 1 MW) with a constant effective stack height of 5 m located at the city hall for California's eleven most populous cities; the emission factor for each technology is the best available in the existing literature (EPA, 2000a). Fuel cells are not shown because an emission factor for HCHO is not available. (See Figure 9 caption for interpretation of the interquartile box plot.)

III.C Equalizing Exposure Burdens

An important goal of our research is to provide an estimate of emission factors that small-scale DG-technologies should meet to present no greater exposure hazard per unit of electricity generated (i.e., intake-to-generation ratio) than do central station plants. Our estimates are presented in Figures 38-39. We focus on the comparison of small-scale DG to central stations because our current system is so heavily reliant on central stations that the incursion of new technologies will mostly displace either existing or new central station production. Which EGUs will be displaced is a question that only a system dispatch model can answer in a detailed manner. However, it has been argued that the system-average emission factor is a good estimate for what emissions will be displaced by an incoming small-scale DG unit (Bluestein, 2000). Because the median is less sensitive to outlying values, we compare the median existing central station to the median for the five small-scale DG technologies, acknowledging that for any specific hour that a DG unit runs, its generation could displace a unit anywhere in the range we have modeled. On the other hand, if one believes that DG will only compete for capacity additions, then the most sensible comparison is to new combined-cycle turbines. Thus, we have provided results based on both comparisons.

Given the inherent difference in intake fraction between the two paradigms of electricity generation, new DG technologies must be much cleaner than central stations to avoid increasing population intake of pollutants from electricity generation. For both primary $PM_{2.5}$ and HCHO, the emission factors required for co-located small-scale DG technologies to achieve the intake-to-generation ratios of existing central stations are an order of magnitude cleaner than the existing central station they would replace. This level is nearly equal to CARB BACT for new central stations for formaldehyde and is a factor of three lower than BACT in the case of primary $PM_{2.5}$. To achieve the intake-to-generation ratios equivalent to BACT-controlled existing central stations, co-located new DG technologies will have to reduce primary $PM_{2.5}$ and formaldehyde emissions by another order of magnitude or more for formaldehyde and 50% for primary $PM_{2.5}$. This final level is ten times lower than currently required under BACT for formaldehyde and PM.

Small-scale DG technologies located in urban downtowns (assessed at the sites of city halls in this analysis) have an even higher hurdle. To equal the IGRs of either existing central stations or BACT-controlled central stations, small-scale DG technologies located in these areas will have to reduce their emission factors by another 30-50%, owing to the inherent increase in intake fractions for these locations.

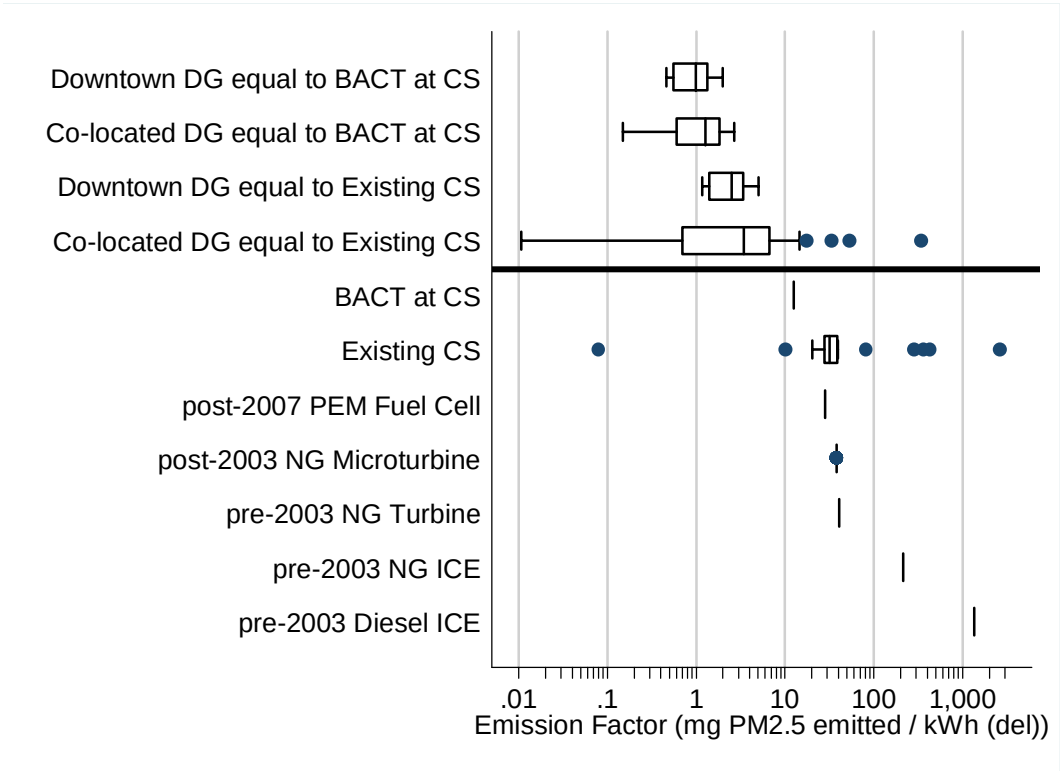

Figure 38. Interquartile box plots of primary $PM_{2.5}$ emission factors for small-scale (< 1 MW) DG technologies necessary to equal the IGR of the existing units or BACT-controlled existing units. Other emission factors are shown for reference. The emission factor for each technology is the best available in the existing literature (BACT: CARB, 1999; existing: EPA, 2004b; all hypothetical DG (< 1 MW) technologies: Samuelsen *et al.*, 2003). (See Figure 9 caption for interpretation of the interquartile box plot.)

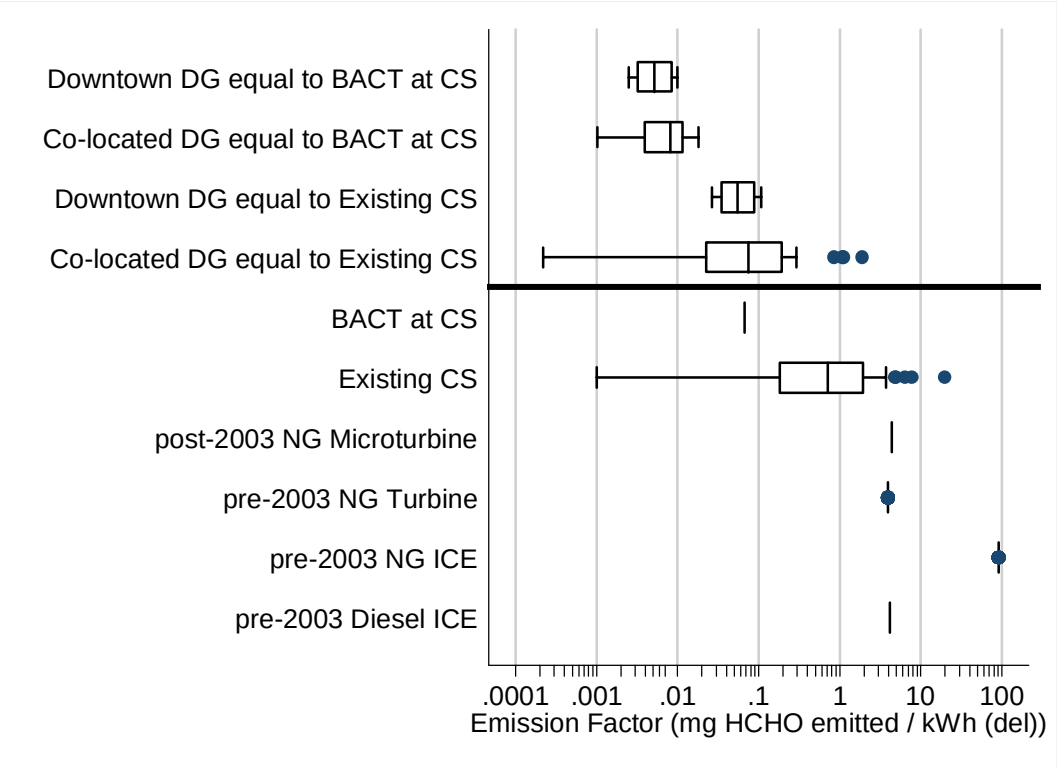

Figure 39. Interquartile box plots of HCHO emission factors for small-scale (< 1 MW) DG technologies necessary to equal the IGR of the existing units or BACT-controlled existing units. Other emission factors are shown for reference. The fuel cell is not shown because there is no available emission factor for HCHO. The emission factor for each technology is the best available in the existing literature (BACT: EPA, 2000a (for a combined-cycle turbine with catalytic reduction); existing: EPA, 2003b; all hypothetical DG (< 1 MW) technologies: EPA, 2000a). (See Figure 9 caption for interpretation of the interquartile box plot.)

III.D Summary of Results

The intake fraction and intake-to-generation ratio are useful metrics to compare the potential for differential population inhalation intake of air pollutants emitted by the two paradigms of combustion-based electricity generation. A tabulation of the intake fraction and intake-to-generation ratio results, as well as the emission factors, for selected California central station units is found in Table 21. Table 22 presents these same measures for the cogeneration and existing DG (> 1 MW) cases. Table 23 presents the iF and IGR results for the hypothetical DG cases co-located at the sites of the central stations, while Table 24 presents analogous information for the hypothetical DG cases co-located at the sites of the cogeneration and existing DG (> 1 MW) sites as well as in the downtown districts of the eleven most populous California cities.

The median annual-average, conserved pollutant intake fraction for the existing central stations we assessed (n = 25) is approximately 0.8 per million with a range of approximately 0.05 to 2.5 per million. The central tendencies for existing cogeneration plants (n = 6) are slightly lower and for existing DG (> 1 MW) a factor of 3 higher (n = 6), owing to differences in population density surrounding the units and characteristic effective stack heights, respectively. Hypothetically co-located small-scale DG (< 1 MW) technologies, with constant effective stack heights of 5 m, have median conserved pollutant iFs of approximately 10, 4 and 10 per million for central station, cogeneration and DG (> 1 MW) sites, respectively. Small-scale DG technologies hypothetically located at eleven California city halls exhibit iFs that are a factor of two higher than those co-located at central stations (16 per million). The range of conserved pollutant iFs considering all hypothetical DG cases is 0.3 per million (at the site of the Humboldt Bay central station) to nearly 33 per million (at Los Angeles city hall).

Through comparisons amongst the cases selected, we have explored the importance of many elements of the three key factors that influence the intake fraction. **Proximity** was evaluated in terms of effective stack height, **persistence** in terms of pollutant decay, and **population** in terms of its density. The two factors that had the greatest impact on intake fraction were effective stack height and downwind population density, each contributing a one order-of-magnitude or larger effect. Across both urban and rural cases, we observed an order of magnitude reduction in iF for every order of magnitude increase in annual-average effective stack height (over the 20 – 1000 m range of our cases). Keeping meteorology and population downwind constant, if we hypothetically reduce the effective stack height of existing units to near ground level (where small-scale DG will likely emit), annual-average intake fraction is typically reduced by an order of magnitude or two. Whether an existing unit is in an urban area compared to a rural one can increase the intake fraction by an order of magnitude. By contrast, persistence had a smaller effect over the range of conditions considered. The atmospheric decomposition of primary formaldehyde emissions reduced the intake fraction, on average, by 20% for the cases explored here.

Figure 40 summarizes the median values of primary $PM_{2.5}$ and formaldehyde intake-to-generation ratio for central stations (existing and BACT-controlled) and microtubines located at the sites of the central stations and in the urban core. After accounting for the differences in efficiency, emission rates and line losses between the two paradigms of electricity generation, the median IGRs for microturbines located in urban downtowns were one to two orders-of-magnitude higher than for the existing

central stations considered in this study. Locating microturbines at the sites of the central stations only reduces these differentials by a factor of two. If we were to limit the siting of microturbines to rural areas, IGRs would still be a factor of three to twenty higher than for the median of all central stations assessed (for primary $PM_{2.5}$ and HCHO, respectively; compared to rurally-sited central stations, microturbine IGRs are another order of magnitude greater. Even employing the lowest-emitting DG technology – fuel cells – results in only a 25% improvement in primary $PM_{2.5}$ IGR compared to microturbines. [39] The other, more common DG technologies – ICEs and turbines – have IGRs 10% to a factor of 36 times worse for primary $PM_{2.5}$; for HCHO, IGRs could improve by ~10% (for diesel ICEs and NG turbines) or increase by a factor of 20 (NG ICE).

To equal the exposure burden of existing central station generation, primary $PM_{2.5}$ emission factors for small-scale DG located in the urban core must be reduced by a order of magnitude compared to the emission factor of fuel cells (see Figure 38). To equal the IGR of BACT-controlled central stations, a reduction of another factor of two is required. For formaldehyde emissions, the necessary emission factors for small-scale DG technologies located in downtowns to equal the exposure burden of central stations and BACT-controlled central stations are two to three orders-of-magnitude lower than those achieved by the cleanest small-scale DG technology (see Figure 39). These requirements are primarily a result of the inherent disadvantage that distributed generation has in terms of intake fraction. If small-scale DG were sited outside of downtown urban locations, the emission factors could only be loosened by up to a factor of two for formaldehyde and only 50% for $PM_{2.5}$.

[39] Recall that we could not find a formaldehyde emission factor for fuel cells. Thus, no HCHO IGR is calculated for this technology.

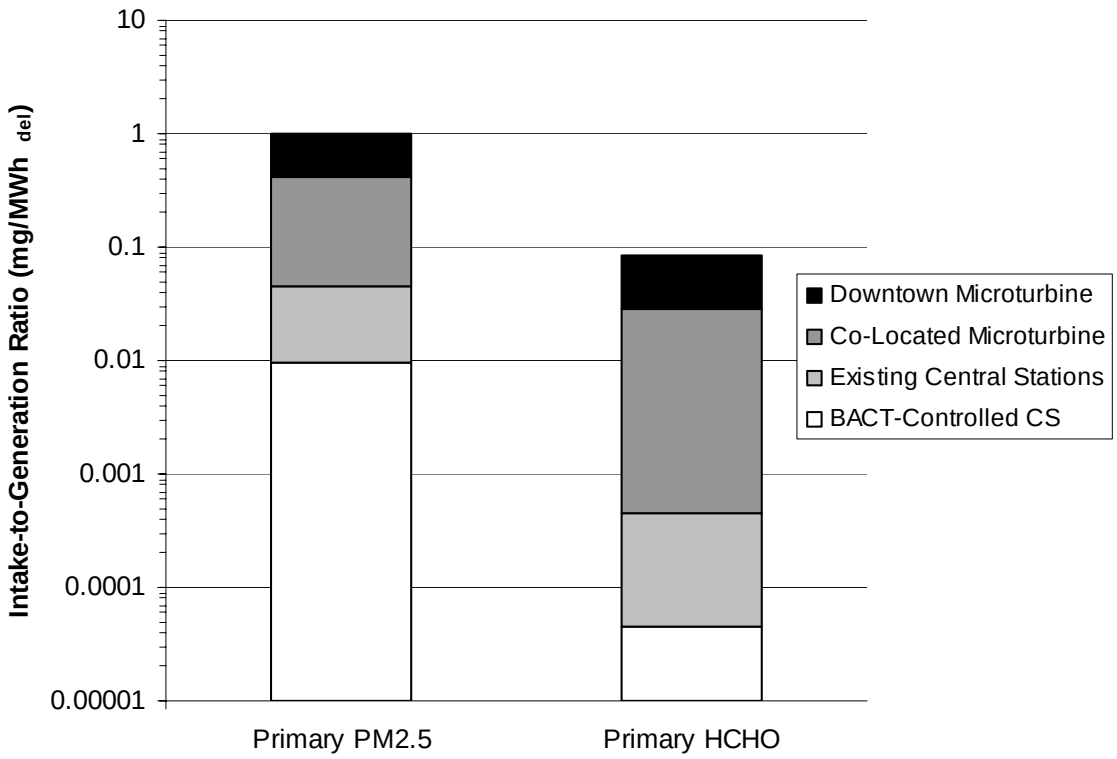

Figure 40. Summary of median intake-to-generation ratios for primary $PM_{2.5}$ and formaldehyde for central stations (existing and BACT-controlled) and microturbines located at the sites of the central stations as well as in the downtown areas of the eleven most populous cities in California.

Table 21. Summary of results for central station existing units.

Central Station	Urban / Rural	Fuel[a]	Emission Factor (mg/kWh_{del})		Intake Fraction (per million)		Intake-to-Generation Ratio[c] (mg/MWh_{del})	($\mu g/MWh_{del}$)
			Primary $PM_{2.5}$	HCHO[b]	Primary $PM_{2.5}$	HCHO[b]	Primary $PM_{2.5}$	HCHO[b]
Alamitos	Urban	NG, Diesel	32	1.2	1.9	1.5	0.060	1.9
Coachella	Rural	NG, Diesel	82	0.72	0.66	0.56	0.054	0.40
Contra Costa	Rural	NG	22	0.12	0.15	0.12	0.0034	0.014
El Segundo	Urban	NG	20	0.48	3.1	2.5	0.062	1.2
Encina	Urban	NG, Diesel	24	3.7	0.14	0.11	0.0034	0.42
Etiwanda	Urban	NG	34	0.18	1.1	0.85	0.038	0.16
Humboldt Bay	Rural	NG, Diesel, Residual Oil	28	0.16	0.057	0.051	0.0016	0.0082
Hunters Point	Urban	NG, Diesel	40	0.27	0.88	0.74	0.035	0.20
Huntington Beach	Urban	NG, Diesel, Residual Oil	31	0.86	1.4	1.1	0.043	0.94
Kearny	Urban	NG, Diesel	430	20	0.78	0.66	0.33	13
Magnolia	Urban	NG	2600	7.7	2.5	2.0	6.6	16
Mandalay	Urban	NG, Diesel, Residual Oil	30	0.90	0.45	0.35	0.013	0.31
Morro Bay	Rural	NG, Diesel	28	0.038	0.054	0.046	0.0016	0.0017
Moss Landing	Rural	NG, Residual Oil	29	2.0	0.12	0.095	0.0033	0.1880
Mountainview Power	Urban	NG	35	0.37	1.7	1.2	0.059	0.45
North Island	Urban	NG, Diesel	360	6.5	1.0	0.85	0.36	5.5
Oakland	Urban	Diesel	280	4.9	0.63	0.57	0.18	2.7
Ormond Beach	Rural	NG	32	0.53	0.52	0.38	0.016	0.20
Pittsburg	Urban	NG	23	0.55	0.25	0.19	0.0057	0.10
Puente Hills	Urban	LFG, Diesel, NG	10	0.017	1.5	1.2	0.015	0.021
Redding Power	Rural	NG	34	0.069	0.12	0.11	0.0042	0.0075
Redondo Beach	Urban	NG	30	1.8	0.45	0.39	0.014	0.69
Riverside Canal	Urban	NG	39	0.00092	2.0	1.5	0.079	0.0014
South Bay	Urban	NG, Diesel, Kerosene, Residual Oil	32	4.8	1.5	1.3	0.047	6.1
Valley	Urban	NG, Diesel, Residual Oil	0.079	1.7	1.9	1.5	0.00015	2.6

Data sources: Emission factors and fuel: EPA, 2003b; EPA, 2004b, except Magnolia and Coachella emissions (CARB, 2004b).

[a] Fuel burned based on SCCs listed for electricity generation, in descending order of proportion of emissions due to combustion of that fuel.

[b] HCHO = formaldehyde.

[c] Results may not multiply due to rounding.

Table 22. Summary of results for the cogeneration[a] and DG (> 1 MW) existing units.

Cogeneration	Urban / Rural	Fuel[b]	Intake Fraction (per million)	
			Primary $PM_{2.5}$	HCHO[c]
Hanford	Rural	Petroleum Coke, NG, Diesel	0.42	0.32
Lincoln	Rural	Woodwaste	0.53	0.42
Live Oak	Rural	NG	0.47	0.36
Monterey Regional WPCA	Urban	NG, Diesel, Digester Gas	0.27	0.23
Mt. Poso	Rural	Coal (Bituminous)	0.11	0.085
San Antonio Community Hospital	Urban	NG	6.6	5.0

Existing DG (> 1 MW)	Urban / Rural	Fuel[b]	Emission Factor (mg/kWh_{del})		Intake Fraction (per million)		Intake-to-Generation Ratio[d] (mg/MWh_{del})	Intake-to-Generation Ratio[d] ($\mu g/MWh_{del}$)
			Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]
Marina Landfill	Rural	LFG	180	0.0076	1.3	1.1	0.21	0.0082
Olinda Landfill	Urban	LFG	12	1.0	3.3	2.5	0.037	2.4
Pebbly Beach	Rural	Diesel	2400	2.4	1.1	0.74	2.3	1.8
Penrose Landfill	Urban	LFG	-[e]	2.1	5.9	4.9	-	10
Salinas Landfill	Rural	LFG	-[e]	350	1.0	0.76	-	240
Solar Turbines	Urban	NG, Diesel	210	20	4.8	4.1	0.89	73

Data sources: Emission factors and fuel: EPA, 2003b; EPA, 2004b.

[a] Emission factors and intake-to-generation ratios are not shown for cogeneration plants owing to uncertainty in emissions.

[b] Fuel burned based on SCCs listed for electricity generation, in descending order of proportion of emissions due to combustion of that fuel.

[c] HCHO = formaldehyde.

[d] Results may not multiply due to rounding.

[e] No emissions were reported for this plant in either the National Emission Inventory (EPA, 2004b) or CARB's Emission Inventory (CARB, 2004b).

Table 23. Summary of results for microturbines co-located at the sites of the existing central stations. (Use the multiplicative table (Table 25) to achieve results for other hypothetical DG technologies as well as the hypothetical case of existing units controlled to California BACT levels.)

Central Station Site	Urban / Rural	Technology	Emission Factor[b] (mg/kWh_{del})		Intake Fraction[d] (per million)		Intake-to-Generation Ratio[b,e] (mg/MWh_{del})	($\mu g/MWh_{del}$)
			Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]
Alamitos	Urban	Microturbine	38	4.4	18	13	0.68	56
Coachella	Rural	Microturbine	38	4.4	3.1	2.1	0.12	9.1
Contra Costa	Rural	Microturbine	38	4.4	13	7.5	0.49	33
El Segundo	Urban	Microturbine	38	4.4	18	12	0.67	54
Encina	Urban	Microturbine	38	4.4	6.6	4.4	0.25	19
Etiwanda	Urban	Microturbine	38	4.4	11	6.9	0.41	30
Humboldt Bay	Rural	Microturbine	38	4.4	0.27	0.21	0.010	0.94
Hunters Point	Urban	Microturbine	38	4.4	9.2	6.5	0.35	29
Huntington Beach	Urban	Microturbine	38	4.4	12	8.6	0.47	38
Kearny	Urban	Microturbine	38	4.4	10	6.9	0.38	31
Magnolia	Urban	Microturbine	38	4.4	19	14	0.73	64
Mandalay	Urban	Microturbine	38	4.4	6	4	0.23	19
Morro Bay	Rural	Microturbine	38	4.4	2.3	1.5	0.086	6.7
Moss Landing	Rural	Microturbine	38	4.4	6.4	3.9	0.24	17
Mountainview Power	Urban	Microturbine	38	4.4	8.8	5.6	0.33	25
North Island	Urban	Microturbine	38	4.4	6.9	5.0	0.26	22
Oakland	Urban	Microturbine	38	4.4	12	9.4	0.47	41
Ormond Beach	Rural	Microturbine	38	4.4	11	6.4	0.40	28
Pittsburg	Urban	Microturbine	38	4.4	9.2	5.9	0.35	26
Puente Hills	Urban	Microturbine	38	4.4	27	17	1.0	73
Redding Power	Rural	Microturbine	38	4.4	1.2	0.88	0.046	3.9
Redondo Beach	Urban	Microturbine	38	4.4	18	13	0.70	58
Riverside Canal	Urban	Microturbine	38	4.4	9.9	6.3	0.37	27
South Bay	Urban	Microturbine	38	4.4	9.3	7.2	0.35	32
Valley	Urban	Microturbine	38	4.4	14	10	0.53	45

Data sources: HCHO emission factor: EPA, 2003a; primary $PM_{2.5}$ emission factor: Samuelsen *et al* ., 2003.

[a] Fuel burned based on SCCs listed for electricity generation, in descending order of proportion of emissions due to combustion of that fuel.

[b] Use multiplicative factors (Table 25) to calculate the emission factor or intake-to-generation ratio appropriate to a different small-scale DG technology.

[c] HCHO = formaldehyde.

[d] The intake fraction is constant across technologies. Do not use multiplicative factor on this figure.

[e] Results may not multiply due to rounding.

Table 24. Summary of results for microturbines co-located at the sites of the existing cogeneration and DG (> 1 MW) plants. (Use the multiplicative table (Table 25) to achieve results for other hypothetical DG technologies as well as the hypothetical case of existing units controlled to California BACT levels.)

Cogeneration Site	Urban / Rural	Technology	Emission Factor[b] (mg/kWh$_{del}$)		Intake Fraction[d] (per million)		Intake-to-Generation Ratio[b,e] (mg/MWh$_{del}$) (μg/MWh$_{del}$)	
			Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]
Hanford	Rural	Microturbine	38	4.4	2.1	1.3	0.078	5.7
Lincoln	Rural	Microturbine	38	4.4	4.9	3.0	0.19	13
Live Oak	Rural	Microturbine	38	4.4	2.1	1.3	0.078	5.8
Monterey Regional WPCA	Urban	Microturbine	38	4.4	4.9	3.8	0.19	17
Mt. Poso	Rural	Microturbine	38	4.4	2.2	1.4	0.084	6.3
San Antonio Community Hospital	Urban	Microturbine	38	4.4	15	10	0.57	46

DG (> 1 MW) Site	Urban / Rural	Technology	Emission Factor[b] (mg/kWh$_{del}$)		Intake Fraction[d] (per million)		Intake-to-Generation Ratio[b,e] (mg/MWh$_{del}$) (μg/MWh$_{del}$)	
			Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]
Marina Landfill	Rural	Microturbine	38	4.4	5.5	3.6	0.21	16
Olinda Landfill	Urban	Microturbine	38	4.4	18	11	0.70	50
Pebbly Beach	Rural	Microturbine	38	4.4	6.8	3.8	0.26	17
Penrose Landfill	Urban	Microturbine	38	4.4	16	12	0.62	54
Salinas Landfill	Rural	Microturbine	38	4.4	8.0	4.6	0.30	20
Solar Turbines	Urban	Microturbine	38	4.4	12	9.2	0.44	40

City Hall	Urban / Rural	Technology	Emission Factor[b] (mg/kWh$_{del}$)		Intake Fraction[d] (per million)		Intake-to-Generation Ratio[b,e] (mg/MWh$_{del}$) (μg/MWh$_{del}$)	
			Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]	Primary $PM_{2.5}$	HCHO[c]
Anaheim City Hall	Urban	Microturbine	38	4.4	28	20	1.1	89
Fresno City Hall	Urban	Microturbine	38	4.4	7.8	6.5	0.29	29
Los Angeles City Hall	Urban	Microturbine	38	4.4	33	26	1.3	115
Long Beach City Hall	Urban	Microturbine	38	4.4	19	14	0.71	61
Oakland City Hall	Urban	Microturbine	38	4.4	16	13	0.59	56
Riverside City Hall	Urban	Microturbine	38	4.4	12	7.8	0.44	34
Sacramento City Hall	Urban	Microturbine	38	4.4	10	7.2	0.36	32
San Diego City Hall	Urban	Microturbine	38	4.4	12	10	0.46	43
San Jose City Hall	Urban	Microturbine	38	4.4	12	10	0.47	43
Santa Ana City Hall	Urban	Microturbine	38	4.4	29	23	1.1	100
San Francisco City Hall	Urban	Microturbine	38	4.4	19	16	0.71	69

Data sources: HCHO emission factor: EPA, 2003a; primary $PM_{2.5}$ emission factor: Samuelsen *et al*., 2003.

[a] Fuel burned based on SCCs listed for electricity generation, in descending order of proportion of emissions due to combustion of that fuel.

[b] Use multiplicative factors (Table 25) to calculate the emission factor or intake-to-generation ratio appropriate to a different small-scale DG technology.

[c] HCHO = formaldehyde.

[d] The intake fraction is constant across technologies. Do not use multiplicative factor on this figure.

[e] Results may not multiply due to rounding.

Table 25. Multiplicative factors to calculate emission factors and intake-to-generation ratios for the technologies listed below using the results in Tables 23 and 24.

Technology	Multiplicative Factor	
	Primary $PM_{2.5}$	HCHO[a]
Diesel ICE	36	0.94
NG ICE	5.7	21
NG Turbine	1.1	0.89
Microturbine	1	1
Low Temperature Fuel Cell	0.75	N/A[b]
BACT	0.33	0.015

These multiplicative factors are derived as the ratio of the emission factors from the technology in question to the emission factor for a microturbine, for each pollutant.

Data sources: HCHO emission factor: EPA, 2003a; primary $PM_{2.5}$ emission factor: Samuelsen *et al.*, 2003, except BACT, which comes from CARB, 1999 ($PM_{2.5}$) and EPA, 2000a (HCHO).

[a] HCHO = formaldehyde.

[b] Fuel cells have no reported emission factor for formaldehyde.

IV. Conclusions

Political and market leaders predict rapid growth in the penetration and deployment of DG in the United States and around the world (DOE, 2000; Allied Business Intelligence, 2002). Regulatory actors and researchers have recently begun to assess the significance of this expansion with regard to air quality and public health. Already, we know that electricity generation is a significant contributor to state and national emission inventories. In addition, recent studies have demonstrated that power plants impose significant direct human health impacts and monetary damages based on their emissions of criteria pollutants (e.g., Rabl and Spadaro, 2000; Levy *et al.*, 1999). Based on the findings of this study centered in California and on the assumption that the most mature DG technologies — i.e., those that are combustion-based — will capture much of the early market, there is reason to caution against unquestioning support of DG and to continue investigations regarding the potential air quality and health impacts of DG technologies.

There are fundamental differences between the DG and central-station paradigm in the spatial association between where pollutants are emitted and where people are exposed. The closer vertical proximity of DG technologies can increase the fraction of pollutants inhaled by an order of magnitude compared to our current central station approach. When considering that the likeliest siting of DG will be in areas of higher population density than for many central stations, population intake may be increased by another factor of two or more. These differences, expressed here through the intake fraction, place DG at a severe disadvantage if measured in terms of human exposure to atmospheric emissions.

With emission factors for already installed DG technologies higher – and sometimes considerably higher – than for the best-controlled central stations, the mass of pollutants inhaled by the exposed population per unit of electricity delivered (i.e., intake-to-generation ratio) can be up to three orders-of-magnitude greater for DG compared to existing central stations. Despite uncertainty in where small-scale DG units are and will be sited, the findings of this research highlight the increased exposure potential these units present.

To ensure that the public health consequences of electricity generation do not become worse will require emission characteristics from new DG technologies that are much better than from central station facilities to make up for DG's inherent intake fraction handicap. For primary $PM_{2.5}$ emissions, DG emission factors will have to be an order-of-magnitude less than existing central stations in order to equal their exposure burden per unit of electricity delivered; a reduction of another factor of two is necessary when comparing DG to new, central stations controlled to California BACT levels. For the case of primary formaldehyde, emission factors for new small-scale DG must be an order of magnitude lower than existing or new central stations in order to equalize exposure burden. The emission factors required to equalize exposure burden are one to three orders of magnitude less than those achieved by the cleanest burning DG technologies of today – fuel cells and microturbines.

The CARB emission standard requires emission factors from new DG to meet the level of BACT for some pollutants by 2007. However, equal mass emission rates do not imply equal air pollutant exposure impact. As evidenced by the above-mentioned

findings, the exposure burden from distributed generation technologies will remain significantly greater than for central stations unless additional emission factor reductions are made. Furthermore, the CARB emission standard only mandates specific output-based limits on the emissions of two pollutants, plus total volatile organic compounds. Whether emissions of pollutants not expressly regulated will also be reduced is uncertain. What is clear is that current DG emission factors for other pollutants of concern, such as formaldehyde, can impose significantly increased inhalation exposures due to their close proximity to downwind populations.

Using waste heat in combined heat and power applications of small-scale DG can help mitigate the exposure increase by offsetting other emissions, but even the 30-40% efficiency gains will not account for the order-of-magnitude or greater difference in potential exposures, at least not on an individual unit basis. This study did not consider the system-wide effects of full-scale deployment of DG in CHP mode, which remains an open issue for future research.

The scale of the difference in exposure potential between the two paradigms of electricity generation and the elucidation of their underlying causes suggest that our broad findings may be true beyond the limits of the specific cases considered. Continued work could improve the robustness of our conclusions through more elaborate treatment of several aspects of the assessment. However, confidence in our approach is gained by the agreement between the results of this study and similar ones, leading us not to expect substantial changes in our main conclusions.

To date, regulatory policy for DG in California has focused on limiting mass emission rates to a level consistent with good central-station performance. However, even this level of performance could lead to increased population exposures to many pollutants. To be protective of public health, regulators should consider the potential for increased exposures if air pollutant-emitting DG technologies are sited in densely populated areas. This consideration would be especially relevant during CARB's 2005 mid-course review of the emission standard. To that end, we have provided estimates of the emission factors necessary for new small-scale DG technologies to equal the exposure potential of existing and BACT-controlled central station facilities in California. Additionally, our results could provide further impetus for regulators to promote non-emitting DG technologies, such solar photovoltaics. A strong move in this direction would capture the many benefits of DG while leading to improvements in ambient air pollution and reductions in greenhouse gas emissions — a clean, distributed energy future.

V. Recommendations

The research reported here demonstrates progress in understanding the environmental health implications of a shift in electricity generation from a system relying on large, central station power plants to one relying on distributed generation technologies. However, much work remains to better characterize and quantify the potential impacts. Refinements of certain aspects of our current model would yield improvements in its accuracy. Additional efforts could expand the scope of the current model in key dimensions. Furthermore, there are issues that would require a new

modeling approach to achieve significant progress. Recommendations for future research are prioritized within these three categories.

This research used a case study approach to estimate annual-average intake fractions and intake-to-generation ratios for particular central stations in California and multiple DG technologies. The results indicate the expected scale of intake fractions (iF) and intake-to-generation ratios (IGR) from these different modes of electricity generation. However, as with any modeling exercise, various assumptions, simplifications and other decisions could have an influence on the outcomes achieved. Thus, a sensitivity analysis exploring the range of the parameter space (e.g., varying effective stack height systematically at one site) as well as various modeling decisions (e.g., urban/rural and elevated/ground-based selection and numerical as opposed to analytical integration in the crosswind direction) is prudent. After completion of the sensitivity analyses, one would be in a better position to assess the uncertainty – quantitatively and qualitatively – of our results.

While many experts believe that new distributed generation is most economical when usefully capturing the waste heat, we found it difficult to accurately allocate emissions from existing cogeneration plants to electricity generation. Thus, we were unable to estimate intake-to-generation ratios for this category of existing unit. Success in locating other sources of emission data or alternative methods of emissions allocation would allow us to test whether this mode of electricity generation offers exposure benefits compared to electricity-only units.

Two ideas for incremental improvement to the current modeling framework include a more refined approach to treatment of the plume's passage through the mixed layer and locating a source of Mexican population data at finer spatial resolution so that our population intake assessment is equally robust on both sides of the border.

Finally, two additional analyses would significantly add to the richness of our results. An investigation of the spatial distribution of inhalation intake by distance downwind and compass direction would allow us to determine where the greatest exposure burden is experienced. However, disproportionate burden is not only a spatial function but can also be examined demographically. Both of these lines of inquiry can be explored within the framework of our existing model.

Other important issues would require a significant expansion of the current model to address. We believe that with a reasonable-scale effort the current model could be adapted to address secondary formation of nitrogen-containing species (gaseous and particulate). This should be the highest priority near-term goal as NO_2 and secondary particulate matter have been identified in a previous hazard rankings as the electricity generation-related pollutants with the greatest potential health risk (Heath *et al.,* 2003) and for their importance to air quality compliance. However, assessing the contribution of electricity generation to the formation of other secondary pollutants such as ozone is a more complex matter that would require an alternative modeling approach. For example, one might need to apply a Gaussian-style subgrid plume model within the framework of a trajectory or urban airshed model to accurately capture the combined complexities of atmospheric photochemistry and transport from localized sources.

Two issues with regard to dispersion modeling deserve high-priority attention. First, periods of low or no wind (i.e., calms) could represent significant health hazards to nearby populations. These conditions occur with sufficient frequency that, while analytically impossible within the Gaussian plume framework, an exposure assessment should account for their potential impact through other means. Also, since short stacks

and decaying pollutants both emphasize population intake in the region near the source, a better understanding of the concentration profile within a few kilometers, and especially within 500 meters, is important for accurately estimating population intake.

A more nuanced approach to time-varying rates of emission, downwind concentrations, breathing rates and population location (i.e., mobility), would provide a more realistic assessment of population exposure to air pollutants emitted from electricity generation. For instance, for load-following or peaking units in California, higher-than-average emissions occur during times of greatest dispersion: summer afternoons. To better understand any potential bias in our assumption of constant emissions one would need a timeseries of emissions and generation to match the hourly meteorological data we already utilize. Finally, a different approach to classifying a source as urban or rural on a ratio rather than an categorical scale would allow better characterization of the relationship between population density and population inhalation intake. Such a scheme could utilize GIS to determine the population within a certain radius weighted by the prevalence of wind directions and a function reflective of the decay of a pollutant's concentration by distance downwind.

Four other research efforts that would expand the scope of the current modeling effort should be considered. First, expanding the modeling domain to include a regional estimate of population intake (i.e., beyond 100 km) is fundamental to assessing the full burden imposed by electricity generation units, especially central station plants. To address this need, one would need to adopt a trajectory model and additional meteorological data to track the plume as it meanders through complex terrain with changing meteorological conditions. Other research groups have developed modeling tools for this purpose, which could be utilized. Plume tracking might prove valuable even within 100 km.

Second, the system-wide effects of full-scale DG deployment within an urban airshed are not addressed in the current model and could be non-intuitive. One approach to addressing this issue would involve an aggregation of the impacts of individual electricity generation units along with careful treatment of the emissions offsets that would occur with DG deployed in a CHP mode. Another approach would be to move to an urban airshed model where total emissions from all DG and offset sources could be spatially- and temporally evaluated, along with the effects of background concentrations and other parameters.

Third, our current research employs a dispersion model to conduct an exposure assessment. Leveraging the population intake results, one could extend this analysis to risk assessment end points. An assessment of cancer risk would be relatively straightforward; however, the evaluation of pollutants whose dose-response curves exhibit thresholds, nonlinear behavior or are strong functions of dose rate would be considerably more complex. Finally, non-electricity generation-related sources could be incorporated to estimate cumulative personal exposure to certain pollutants.

Our research has revealed the potential for a large relative exposure impact from shifting centralized electricity generation to distributed generation. The significance of electricity generation as a source of air pollutants and societal health impacts argues that additional research is warranted to refine and expand the efforts we have begun. While the distributed generation industry is still nascent, continued research along the directions outlined above is crucial and timely.

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VIII. Glossary of Terms, Abbreviations, Units of Measure and Symbols

Terms and Abbreviations

AP-42	compilation of air pollutant emission factors maintained by the US Environmental Protection Agency
AQMD	air quality management district
atmospheric stability	condition of the atmosphere governing rate of vertical mixing
BACT	best available control technology (referring to the California regulatory standard)
baseload	power plant that is operated nearly continuously, emitting pollutants at a constant rate
calms	atmospheric condition in which wind speed is below detection limit of monitoring instrument
capacity factor	ratio of the actual energy produced in a given period to the theoretical maximum
CARB	California Air Resources Board
CDF	cumulative distribution function
CEC	California Energy Commission
CEM	continuous emission monitor
central station	large power plant used to provide electricity to the transmission and distribution network; as defined in this report, central station existing units are greater than 50 MW capacity and non-cogeneration
CO	carbon monoxide
combined-cycle	power plant that uses a turbine plus a steam generator to improve thermal conversion efficiency
CHP	combined heat and power; electricity generation system that uses waste heat for beneficial purpose
cogeneration (aka cogen)	synonymous with CHP; also referred to in this report as a type of existing unit
conc.	abbreviation for concentration
conserved (pollutant/species)	not removed from the air in an urban basin, except by air flow
control technology	method of reducing pollutant emissions from a source

criteria pollutant	air pollutant whose ambient concentrations must be maintained below the National Ambient Air Quality Standards established by the US Environmental Protection Agency
CS	central station; refers to one of the three types of existing units we define for the purposes of modeling
cumulative intake	sum of air pollutant mass breathed by all members of an exposed population
de minimus	below a minimum threshold for regulatory concern
decaying (pollutant/species)	removed from the air by a transformation process
demand-side resources	any strategy, method or technology to reduce demand for electricity; e.g., energy conservation or increased energy efficiency
DER	distributed energy resources; supply- and demand-side distributed electricity resources
DG	distributed (electricity) generation; generation near the place of use; see also "existing DG (> 1 MW)" and "hypothetical DG (< 1 MW)"
dispersion	spreading of contaminants from regions of high concentration to regions of low concentration
dispersion parameters	mathematical formulations of observed plume spread in three dimensions (x, y, z); often referred to as "sigma curves" for their mathematical representation as $\sigma_{x,y,z}$
distribution network	system for transmitting lower-voltage electricity from sub-stations (which are connected to the transmission network) to sites of use
district	air quality management district
DOE	(United States) Department of Energy
EF	emission factor; mass of pollutant emission per unit of activity, e.g., per heat input or electricity output
effective stack height	height above ground at which pollutants are effectively emitted, accounting for both the physical stack height and plume rise
efficiency	proportion of thermal energy in fuel converted to electricity in a power plant
eGRID	EPA's Electricity & Generation Resource Integrated Database (www.epa.gov/cleanenergy/egrid)
EGU	electricity generation unit; an existing unit regardless of type

EIA	DOE's Energy Information Administration
emission rate	mass of pollutant emitted per unit time
EPA	(United States) Environmental Protection Agency
existing DG (> 1 MW)	existing electricity generation units of less than 10 MW capacity but greater than 1 MW
existing unit	a real electricity generation unit; in this report, of three types: central station, cogeneration, and existing DG (> 1 MW)
fuel cell	a device that converts chemical energy directly to electricity via a modified oxidation process with lower emissions compared to combustion-based processes
Gaussian plume model	mathematical representation of the pollutant concentration profile downwind of a localized source
GIS	geographic information system
GT	(natural) gas turbine
HAPs	hazardous air pollutants; a list of 188 pollutants designated in the 1990 Clean Air Act Amendments and maintained by the US Environmental Protection Agency
hazard ranking / index	measure of the relative degree of hazard posed by exposure to a particular pollutant
HCHO	formaldehyde
hypothetical DG (< 1 MW)	new, small-scale DG technologies of less than 1 MW capacity that are hypothetically modeled at various locations; includes (for this report) natural gas-fired internal combustion engines, turbines and microturbines, diesel-fired internal combustion engines and fuel cells
HypDG	abbreviation for hypothetical DG (< 1 MW) cases
ICE	internal combustion engine
iF	intake fraction, proportion of pollutants emitted from a source inhaled by exposed population
iFCalc	our Excel Macro-based model that directly calculates intake fractions for point sources by way of a Gaussian plume model given population, meteorological and stack configuration inputs
IGR	intake-to-generation ratio, equal to the product of the intake fraction times an appropriate emission factor

inhalation exposure	average pollutant concentration inhaled times the duration of the encounter with that concentration
intake	quantity of an air pollutant inhaled
interquartile range	the range between the 25th and 75th percentiles of a distribution
inversion layer	region of the atmosphere where the temperature rises with height
LDC	least developed country
LFG	landfill gas
line loss	loss of electric power during transmission from the site of generation to the site of use
location category	a dichotomous modeling designation for a specific geographic position as urban or rural, based on US Census designation of Urbanized Areas
loss mechanism	means of pollutant removal other than air flow, e.g. by chemical reaction
MEI	maximally exposed individual
met.	meteorological
meteorological conditions or parameters	mixing height, wind speed and direction, and atmospheric stability prevailing over some time at a particular location
microturbine	a small-scale electricity generation technology that is based on aircraft engine turbo-chargers and uses natural gas as a fuel
mixing height (MH)	distance between the ground and the base of an inversion layer where pollutants mix rapidly
modeling designation	for the purposes of our modeling, there are three necessary designation for the site of electricity generation: location category (urban/rural), release height (elevated/ground-based) and closest meteorological station
modeling domain	the geographic area considered in an air quality model exercise
NAAQS	National Ambient Air Quality Standards
NEI	EPA's National Emission Inventory, of which there are two, one for criteria pollutants and one for hazardous air pollutants (HAPs)
NG	natural gas

NO_2	nitrogen dioxide
NO_3	nitrate radical
no-threshold, dose-response	health hazard model of a pollutant that includes a finite risk for all exposures, no matter how small
NO_x	nitrogen oxides (generally NO + NO_2)
NREL	(United States) National Renewable Energy Laboratory
OEHHA	(California) Office of Environmental Health Hazard Assessment
OH•	hydroxyl radical
order of magnitude	a factor of 10
PCRAMMET	EPA's meteorological pre-processor whose main function is to interpolate hourly mixing heights given twice-daily mixing height and surface meteorological inputs
PEM (fuel cell)	proton exchange membrane fuel cell, a low-temperature fuel cell
photolysis	chemical reaction initiated by the absorption of a photon of light
plume	downwind zone from a localized pollution source over which pollutant levels are elevated because of the source
plume rise	extent to which a plume emitted with momentum or buoyancy moves upward relative to its emission height
$PM_{2.5}$	particulate matter smaller than 2.5 micrometers in aerodynamic diameter
point sources	air pollution sources that have small spatial extent (relative, e.g., to the size of a city)
pop.	abbreviation for population
population density	number of people residing in a zone per unit land area, e.g., people per square kilometer
population intake	cumulative pollutant intake by all members of an exposed population
prevailing wind direction	synonymous with modal wind direction, or, the wind direction that occurs most commonly
primary pollutant	air contaminant directly emitted from source
REL	reference exposure level; concentration that poses no significant health risk from indefinite exposure

secondary pollutant	air contaminant formed by chemical reactions in the atmosphere
SoCAB	South Coast Air Basin
stability class	one of six categories of atmospheric stability, as defined by Pasquill (1961)
stack height	physical height of exhaust chimney from air pollution source
steam turbine	technology for generating electricity that involves the expansion of compressed steam through a turbine
temp.	abbreviation for temperature
threshold	maximum level of pollutant exposure or intake that would cause no adverse health effects
TMY2	Typical Meteorological Year 2 data set published by NREL (1995)
trajectory model	method of accounting for the impact of an air pollution source on the downwind area by tracking the movement of air parcels
transmission network	part of the electrical grid that transports electricity from generators along high voltage power lines to sub-stations and the distribution network
transverse direction	direction in the horizontal plane normal to the prevailing wind flow
VOC	volatile organic compound
well-mixed	possessing uniform concentrations of pollutants
zenith angle	angle between the vertical and the direction of the sun

Units of Measure

μg	microgram; 10^{-6} grams
μm	micrometer, 10^{-6} meters
d	day
g	gram
GW	gigawatt; 10^{9} watts
h	hour
hp	horsepower
kg	kilogram; 10^{3} grams
km	kilometer; 10^{3} meters

kW	kilowatt; 10^3 watts
kWh	kilowatt-hour
lb	pound
m	meter
mg	milligram; 10^{-3} grams
MMBtu	10^6 British thermal units
MW	megawatt; 10^6 watts
s	second
y	year

Symbols Used in Equations

π	pi
σ_x	dispersion parameter in the downwind direction (m)
σ_y	dispersion parameter in the transverse direction (m)
σ_z	dispersion parameter in the vertical direction (m)
C	concentration (g m^{-3})
C_c	concentration of a conserved species (g m^{-3})
C_d	concentration of a decaying species (g m^{-3})
E	steady-state emission rate of a pollutant from a source (g s^{-1} or g h^{-1})
EF	emission factor (e.g., mg per kWh)
H_E	effective stack height of an emission source (m)
I	electric current (A)
iF	intake fraction (-)
iF_c	intake fraction of a conserved pollutant (-)
iF_d	intake fraction of a decaying pollutant (-)
IGR	intake-to-generation ratio (e.g., $mg_{inhaled}$ per kWh_{del})
k	decay constant (s^{-1})
kWh_{del}	kilowatt-hour of electricity delivered to the place of use
M	mixing height (m)
n	index for the number of reflections in the Gaussian plume model (-)
p	power-law exponent (-)

P	population density (people m^{-2})
P_e	electric power (W)
P_h	rate of production of heat energy (W)
Q_B	breathing rate (m^3 h^{-1})
R	electrical resistance (Ω)
U	wind speed (m s^{-1})
U_E	wind speed at effective stack height (m s^{-1})
$\overline{u}_h$	mean wind speed (m s^{-1}) at release height, *h*
$\overline{u}_r$	mean wind speed (m s^{-1}) at the reference height, *r*
V	electrical potential (V)
W	width (m)
x	downwind distance (m)
y	distance in the transverse direction (m)
z	distance in the vertical direction (m)
z_h	height of release (m)
z_r	reference height (m) (typically 10 m)

Appendix A: Procedures for Developing Typical Mixing Height Years

Abstract

Borrowing from the concept of typical meteorological years (as put forward by the National Renewable Energy Laboratory (NREL, 1995)), a typical mixing height year (TMHY) data file contains hourly values of surface and upper air meteorological parameters for a particular surface observation station over a one-year period. Each hour of data contains four surface-level observations -- wind direction, wind speed, ambient temperature and stability class --as well as rural and urban mixing heights. Each month in the TMHY is selected from an individual year (a month/year pair), chosen to represent conditions judged typical of the long-term record for a particular surface station. For example, from the 30-year meteorological record of a particular station, all 30 Decembers are evaluated and the one judged most typical is selected. Twelve individual months so selected are concatenated to form a typical, annual meteorological cycle for use in air dispersion modeling. Use of a typical meteorological year is appropriate when an air dispersion modeler desires typical, or average, outcomes as opposed to ones dependent on conditions of any particular year, worst-case scenario, etc. Whereas the mixing height is necessary in air dispersion modeling, to our knowledge, no typical, annual record of this parameter has been available before this effort.

A.1 Introduction

TMHYs were constructed for ten sites in California and one site in Oregon using the data and programs described in section A.1.1 below. Due to data availability issues that varied between stations, an empirical method was used that was flexible to the amount and quality of data available for a particular location. The general method used for all stations is described in section A.2; results of the selection of month/year pairings for each surface station in California are reported in section A.3. A description of the output of our method is included in section A.4. Additional information regarding input data, station identification and other supplementary files is listed in section A.6 and is available from the authors upon request.

A.1.1 Input Data

The TMHY meteorological files were derived using two EPA-supported meteorological pre-processing programs, both of which are routinely used in air dispersion modeling (EPA, 1998; EPA, 1999). Three sets of data formed the input to these programs:

1. Revised Typical Meteorological Years (TMY2) developed from the National Solar Radiation Data Base (1961 - 1990) (NREL, 1995).

2. Measured or modeled solar radiation and meteorological data for the period 1961-1990 from the Solar and Meteorological Surface Observation Network (SAMSON) (NCDC, 1993).
3. Radiosonde (upper air) data for the period 1946-1996 from the National Climatic Data Center of the National Oceanic and Atmospheric Administration (FSL/NCDC, 1997).

A.1.1.1 Revised Typical Meteorological Years (TMY2s)

A typical meteorological year (TMY) is a set of solar radiation and meteorological elements, consisting of months selected from individual years that have been judged typical of the long-term record, concatenated to form a complete annual cycle. A TMY provides a standard for hourly solar radiation and meteorological data for use in energy modeling (its original purpose) as well as air quality modeling. The TMY data used in this project were derived from the 1961-1990 National Solar Radiation Data Base: the Revised Typical Meteorological Years (TMY2) (NREL, 1995). TMY2s are constructed from observations recorded at a subset of surface stations in the SAMSON network and contain many of the same meteorological elements. However, the TMY2s were used in this study only in the selection of which year is most typical of the long-term record of a particular month, for which the corresponding surface and radiosonde data are taken from the datasets described below. The TMY2s used for the development of TMHYs can be found in File A (available from the authors upon request) (NREL, 1995).

A.1.1.2 SAMSON Data

SAMSON data are a compilation of National Renewable Energy Laboratory solar data and National Weather Service surface observations, containing hourly values of measured or modeled solar radiation and meteorological elements for numerous surface stations for 1961-1990 (NCDC, 1993).

SAMSON data were used in this study (1) to provide hourly values for wind speed, wind direction, and ambient temperature; (2) as input to the each of EPA's meteorological preprocessors (EPA, 1999).

A.1.1.3 Radiosonde Data

Developed jointly by the National Climatic Data Center (NCDC) and the Forecast Systems Laboratory (FSL), radiosonde data contain vertical profiles of upper air meteorological conditions (winds, temperature and pressure) at numerous sites starting in 1946 and continuously updated (FSL/NCDC). Of note, radiosonde measurement stations are not co-located with the surface observation network. In addition, for some locations, data are temporally sparse, presenting challenges to the construction of robust TMHYs.

Radiosonde data for the period 1946 – 1996 were used in this study to provide the vertical profiles of temperature and pressure used in the calculation of mixing height.

A.1.2 Meteorological Preprocessors

This section provides details on the two meteorological preprocessors used in the development of TMHYs: the twice-daily Mixing Heights Program (mixhts.exe), and the hourly interpolation program, PCRAMMET.

A.1.2.1 Mixing Heights Program

EPA's Mixing Height Program (mixhts.exe) computes twice-daily mixing heights (morning and afternoon) from upper air soundings and hourly surface temperatures. Mixing heights are calculated from surface potential temperatures (determined from surface observations and upper air pressure measurements), and observed temperature from upper air temperature measurements (EPA, 1998). It is the output of this program that is used to determine which month/year pair is most typical of the long-term record.

A.1.2.2 PCRAMMET

PCRAMMET (1) calculates hourly values for atmospheric stability from meteorological surface observations and (2) interpolates hourly mixing heights for both urban and rural conditions from the twice-daily mixing height output of mixhts.exe. Pasquill stability classes are calculated from time of day, surface wind speed, and observations of cloud cover and ceiling height. Hourly mixing heights are calculated from twice-daily mixing heights, the local times of sunset and sunrise, and hourly estimates of stability (EPA, 1999).

A.2 Methodology

The development of mixing heights requires surface and upper air data that come from separate observation networks. To produce a realistic mixing height profile requires that both sets of data correspond spatially and temporally. That is, to produce a mixing height record that is representative of the conditions of a particular region, surface and radiosonde data should both come from that region. In addition, these data should correspond in time. Owing to the limited availability and quality of radiosonde data in certain regions in California, considerable attention was paid to determining which month/year pairs met our inclusion criteria and were candidates in the assessment of which was most typical, from which we could construct a TMHY.

Where possible, months and years were paired corresponding to NREL's TMY2 selection. This was our preferred method because mixing heights are a function of surface

data, which were already deemed typical in their assessment. NREL's determination was based on a weighting scheme intended for building energy use calculations, but the parameter weightings are not inconsistent with a weighting scheme oriented towards air quality modeling. However, for roughly half of the California surface stations, this method could not be used due to one or more of the following reasons: 1) lack of available radiosonde data from the same time period that met our data quality requirements; 2) input file errors; or 3) meteorological incompatibilities between surface and radiosonde data. For these cases, we used an empirical method of selecting which month/year pair of input data produced the most typical twice-daily mixing height profile.

The empirical method, described in section A.2.3, is analogous to the Sandia Method used to develop the TMY2 data (NREL, 1995). The method involves developing a cumulative distribution function (CDF) of twice-daily mixing heights for all candidate months and statistically determining which month is most typical of the long-term record. The steps involved in determining which pairs of surface and radiosonde data were candidates in this procedure are described in section A.2.2. The monthly surface data and twice-daily mixing heights for the pairing judged most typical were then input to PCRAMMET to estimate hourly stability class and interpolate hourly rural and urban mixing heights. Finally, the hourly results for each most typical month/year pairing were concatenated to form the typical mixing height year for each surface station in California.

A.2.1 Input Data

This section describes how the surface and radiosonde input to the meteorological preprocessors were selected, paired, and modified before use.

A.2.1.1 Surface and Radiosonde Data Inclusion Criteria

The observation record at many radiosonde stations was either completely missing or seriously incomplete for many years. Radiosonde observations are intrinsically sparse (occurring only twice daily) and atmospheric conditions can change significantly on the order of days. Therefore, we used a relatively conservative inclusion criterion for radiosonde monthly data in keeping with the spirit of EPA guidance on filling of missing meteorological elements (Atkinson and Lee, 1992): any missing afternoon sounding must be preceded by and followed by a valid afternoon sounding. In other words, no more than one sequential afternoon sounding was allowed to be missing. (The inclusion criteria only included a standard for the afternoon mixing height since the morning mixing height is not used in PCRAMMET's hourly interpolation scheme.) All months of radiosonde data that met our inclusion criteria were then candidates for temporal and spatial matching with the surface record. File C details the station-by-station results of the application of our inclusion criteria; this file is available from the authors upon request.

All month/year pairs selected for the TMHYs use surface data with gaps of no more than two hours. There were two stations with exceptions to this rule: Arcata and Santa Maria. Arcata had one month with gaps of up to 12 hours. Santa Maria had much worse quality of surface data available; one month of the TMHY contains gaps of no more than two hours, while the other eleven months contain gaps of between 8 and 11 hours in the surface record. Despite much longer gaps lengths in nearly all months compared to the other stations, we continued construction of a TMHY for this station using the best available input data.

A.2.1.2 Month/Year Pairings

A month/year pairing is defined as a linking of surface and upper air meteorological data, and consists of two input data files containing records for a particular month of a particular year: the surface data from one of the SAMSON observation sites, and the upper air data from a nearby radiosonde station. Owing to the more limited radiosonde data availability, we used surface stations as the hubs, selecting as complete upper air data from a defined set of surrounding radiosonde stations as possible. (We call this set of radiosonde stations a preference group (see section A.2.2.1).)

Any month of radiosonde data meeting the inclusion criteria above is matched to a month of SAMSON surface data as follows:

- If the year of the radiosonde data was in the SAMSON recording period of 1961-1990, surface data from that year was used.
- If the year of the radiosonde data was not in the SAMSON recording period of 1961-1990, surface data from the TMY2-selected year was used.

Within the limits of radiosonde data availability for each surface station, twelve sets of month/year pairings of input data, one for each month of the year, were selected as candidates for determination of which is most typical of the long-term surface reporting period (1961-1990).

A.2.1.3 Modifications Made to SAMSON Data

Our inclusion criterion for SAMSON data allowed for gaps of missing values for meteorological data fields used in the calculation of twice-daily mixing heights, stability class, and hourly urban and rural mixing heights. To obtain a continuous record before inputing to the meteorological preprocessors, any missing values were filled by linear interpolation. Variables for which values were filled were: total sky cover, opaque sky cover, dry bulb temperature, dew point temperature, relative humidity, wind direction, wind speed, and ceiling height. File E (available from the authors upon request) identifies where gaps in data were filled for each station we assessed.

A.2.1.4 Modifications Made to Radiosonde Data

In addition to the significant radiosonde data availability issues addressed through a stringent inclusion criterion, several radiosonde stations provided aberrant data. This situation led the twice-daily mixing heights program to return errors when these soundings were used. Such soundings (1) contained erroneous data, such as listing mixing heights below ground level or reporting ground-level pressure lower than atmospheric measurements; (2) contained lines of missing values prior to the initial surface measurement line, causing mixhts.exe to reject the sounding; (3) contained no lines of data; or (4) incorrectly reported the number of data lines contained in the sounding, causing mixhts.exe to reject the sounding.

For soundings with aberrant measurements or extraneous lines before the surface measurement, the problem lines were simply removed and the reported number of lines changed accordingly. Soundings for which no lines of data were present were removed. For soundings where the number of lines was incorrectly reported, the actual number of lines in the sounding was substituted.

After these modifications, mixhts.exe was able to produce twice-daily mixing heights from these soundings without error. File E (available from the authors upon request) provides more information on where these modifications were made to radiosonde sounding data.

A.2.2 Candidate Months

In the selection of a typical twice-daily mixing height record for a particular station, a candidate month consists of a month of radiosonde data, a month of surface data, and a month of twice-daily mixing heights generated by mixhts.exe (using the previous two data sets as input). Each candidate month meets criteria in each of the following areas:

- Upper air data comes from a prioritized list of radiosonde stations meteorologically related to the surface station of interest (as described in section A.2.1.1).
- Afternoon radiosonde soundings take place during a defined interval of hours (as described in section A.2.1.2).
- Twice-daily mixing heights have a maximum gap length for any missing records (as described in section A.2.1.3).

A set of candidate months consists of candidate months for the same surface station and month over different years. Such a set may include data from multiple radiosonde stations.

A.2.2.1 Radiosonde Station Preference Groups

Each radiosonde station in California (and nearby stations in bordering states) was assigned to one or more preference groups, defined as a set of radiosonde stations sharing a comparable level of meteorological similarity to a particular surface observation station. Characteristics assessed included belonging to the same air basin (see http://www.arb.ca.gov/ei/maps/statemap/abmap.htm for a map of California's air basins), proximity, and having similar elevation and proximity to the coast. Preference groups were prioritized in order of meteorological similarity; if a preference group contained multiple stations, stations were internally ranked. For example, the surface station Bakersfield has two preference groups. The highest preference group contains the Merced/Castle radiosonde station (Weather Bureau Army Navy (WBAN) identification number 23203); the lowest preference group contains the Inyokern, Muroc/Edwards and El Monte radiosonde stations (WBAN 93104, 23114, and 110090, respectively), listed in rank order. File B (available from the authors upon request) lists preference groups for each surface station.

Preference groups always have some degree of meteorological compatibility with their matching surface station, i.e., there are no meteorologically incompatible members. However, it should be noted that the system of assigning and prioritizing preference groups could not be completely objective and relied on researcher judgment. In one case – Arcata – there were no radiosonde stations within a region encompassing similar meteorological conditions. Instead of discarding this site, we produced two TMHY records using the two closest radiosonde stations (Oakland and Medford, OR). Application of both TMHY records to air dispersion modeling provides an opportunity to test the sensitivity of model output to meteorological inputs.

A.2.2.2 Validity of Radiosonde Soundings

Each month of radiosonde data was assigned a lower bound and a higher bound. The lower bound is defined as the difference in hours between 1200 and the earliest hour at which a sounding in the month was taken, while an upper bound is the difference in hours between 1200 and the latest hour at which a sounding in the month was taken. For example, a month with a lower bound of -2 and a higher bound of 4 contains soundings between 1000 and 1600. File C (available from the authors upon request) reports lower and upper bounds for all radiosonde months from stations using the empirical method in the selection of most typical month/year pair.

The twice-daily mixing heights program accepts soundings taken between 1000 and 1500 as input. Therefore, a month is defined as containing valid radiosonde soundings if the lower bound is greater than or equal to -2 and the upper bound is less than or equal to 3; otherwise, the month is defined as containing invalid radiosonde soundings.

A.2.2.3 Maximum Missing Span

Each twice-daily mixing height file was assigned a maximum missing span, defined as the longest sequence of missing values in either the AM or PM mixing heights. The maximum missing span does not report how many spans were missing; only the length of the longest span of missing values is indicated. Missing values resulted either from missing afternoon soundings in the original radiosonde data or from errors during execution of the twice-daily mixing heights program.

According to EPA guidelines for regulatory air quality modeling (Atkinson and Lee, 1992), gaps of one AM or PM mixing height could be acceptably filled by linear interpolation. Therefore, spans of 0 and 1 were considered equivalent.

A.2.3 Selection of Most Typical Candidate Month

After application of the inclusion criteria and using the above definitions, a subset of the month/year pairings of a given month that are candidates in the selection of which is most typical is determined for each surface station after sequentially following these steps:

1. If available, select a candidate month where the radiosonde data was taken from the TMY2-matched year. If there is more than one such candidate month (i.e., from more than one radiosonde station), select the highest ranked radiosonde station within the highest priority preference group available. If no candidates with radiosonde data taken from the TMY2-matched year are available, continue with steps 2-5.

2. Select all month/year pairings where the radiosonde stations are in the highest available preference group.

3. Select month/year pairings with the lowest maximum missing span, where gaps of 0 or 1 are considered equivalent.

4. Select month/year pairings with only valid radiosonde soundings; if none are available, use months where radiosonde data contains invalid soundings.

5. Select month/year pairings where the year of the pairing is in the SAMSON recording period; if none are available, use months where the year of the pairing is not in the SAMSON recording period.

6. For all selected month/year pairings, fill any missing twice-daily mixing heights, as described in section A.4.1.

If by the above process only selects one candidate month, that candidate month is determined to be most typical and is used as input to PCRAMMET to develop the hourly

TMHY. If more than one station is selected by the above process, a long-term cumulative distribution function (CDF) for a particular surface station and particular month is created from the filled, twice-daily mixing heights of all candidate months. The number of candidate months varied widely for the stations we assessed; for example, the month of January for Santa Maria had 32 candidate months, while the month of July for Bakersfield had only two candidate months. For each month, a single CDF was created using the filled twice-daily mixing heights for that month. Candidate monthly CDFs were compared to the long-term CDF using the Finkelstein-Schafer (FS) statistic (Finkelstein and Schafer, 1971) for both the AM and PM mixing height:

$$FS = \frac{1}{n}\sum_{i=1}^{n} \delta_i$$

where:

δ_i	=	absolute value of the difference between the long-term CDF and the candidate month CDF at x_i
n	=	the number of daily readings in a month

A composite FS statistic was determined by averaging the FS statistics for AM and PM mixing heights; the candidate month/year pairing with the lowest composite FS statistic was selected as the most typical and used as input to PCRAMMET to develop the hourly TMHY.

A.2.4 Twice-Daily Mixing Height Program Errors

During execution of the twice-daily mixing heights program, missing values on a particular day were occasionally generated for one of the following reasons:

- No afternoon sounding data was available for that day. In this case, both morning and afternoon mixing heights were marked missing.
- The program could not define an upper height in the sounding for use in interpolating the surface potential temperature. From inspection, this error resulted from incomplete sounding data or cases where the sounding format was not suitable for the program. In this case, both morning and afternoon mixing heights were marked missing.
- The surface potential temperature calculated for either morning or afternoon mixing heights was less than the temperature at the first measurement level of the sounding. The mixing height at the time for which this error occurred was marked missing.

Candidate months were discarded when these errors caused a maximum missing span longer than for other candidate months (i.e., there was no absolute standard for maximum missing applied to all stations). See File E (available from the authors upon request) for information on when these errors occurred.

A.3 Results

This section contains the month/year pairings selected by the above procedure and used to compile the TMHYs for each surface observation station. It also reports, for each station so selected, results of the application of the inclusion and selection criteria used to evaluate each candidate month. Stations are grouped into two lists: TMY2 stations, where month/year pairings correspond to those selected in the TMY2 dataset, and empirical stations, where month/year pairings for at least one month were empirically determined as described in section A.2.3. The TMY2 stations are Long Beach, Los Angeles, Medford OR, Sacramento, San Diego, and San Francisco. The stations where typical year/month pairings were empirically determined are Arcata-Medford, Arcata-Oakland, Bakersfield, Fresno, and Santa Maria.

A.3.1 Month/Year Pairings for TMY2 Stations

All month/year pairings reported below correspond to those selected by NREL in the TMY2 data set (NREL, 1995). Columns 4-8 report the results of the data quality and selection criteria listed above. (File D provides a legend for all WBAN identification numbers. This file is available from the authors upon request.)

Long Beach (WBAN 23129)

Month	Radiosonde Station	Year	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	3131	1967	3	Yes	0	0	0
2	3131	1972	3	Yes	0	0	0
3	3131	1979	3	Yes	0	0	0
4	3131	1981	3	Yes	1	0	0
5	3131	1972	3	Yes	0	0	0
6	3131	1971	3	Yes	0	0	0
7	3131	1969	3	Yes	0	0	0
8	93197	1963	1	Yes	0	0	0
9	3131	1977	3	Yes	0	0	0
10	3131	1979	3	Yes	0	0	0
11	3131	1971	3	Yes	0	0	0
12	3131	1985	3	Yes	0	0	0

Los Angeles (WBAN 23174)

Month	Radiosonde Station	Year	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	3131	1988	3	Yes	0	0	0
2	3131	1971	3	Yes	0	0	0
3	3131	1987	3	Yes	0	0	0
4	93214	1980	3	Yes	0	0	0
5	3131	1972	3	Yes	0	0	0
6	93197	1961	1	Yes	0	0	0
7	3131	1968	3	Yes	0	0	0
8	3131	1970	3	Yes	0	0	0
9	3131	1968	3	Yes	0	0	0
10	3190	1989	3	Yes	0	0	0
11	3131	1968	3	Yes	0	0	0
12	3131	1985	3	Yes	0	0	0

Medford (WBAN 24225)

Month	Radiosonde Station	Year	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	24225	1968	1	Yes	0	0	0
2	24225	1962	1	Yes	0	0	0
3	24225	1980	1	Yes	0	0	0
4	24225	1986	1	Yes	0	0	0
5	24225	1968	1	Yes	0	0	0
6	24225	1981	1	Yes	0	0	0
7	24225	1965	1	Yes	0	0	0
8	24225	1972	1	Yes	0	0	0
9	24225	1973	1	Yes	0	0	0
10	24225	1972	1	Yes	0	0	0
11	24225	1962	1	Yes	0	0	0
12	24225	1970	1	Yes	1	0	0

Sacramento (WBAN 23232)

Month	Radiosonde Station	Year	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	23230	1967	2	Yes	0	0	0
2	23230	1981	2	Yes	2	0	0
3	23230	1985	2	Yes	0	0	0
4	23230	1974	2	Yes	0	0	0
5	23230	1966	2	Yes	0	0	0
6	23230	1971	2	Yes	0	0	0
7	23230	1968	2	Yes	0	0	0
8	23230	1964	2	Yes	0	0	0
9	23230	1966	2	Yes	0	0	0
10	23230	1981	2	Yes	0	0	0
11	23230	1987	2	Yes	0	0	0
12	23230	1986	2	Yes	1	0	0

San Diego (WBAN 23188)

Month	Radiosonde Station	Year	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	3131	1988	1	Yes	0	0	0
2	3131	1970	1	Yes	0	0	0
3	3131	1970	1	Yes	0	0	0
4	3131	1968	1	Yes	0	0	0
5	3131	1965	1	Yes	0	0	0
6	3131	1973	1	Yes	0	0	0
7	3131	1974	1	Yes	0	0	0
8	3131	1961	1	Yes	0	0	0
9	3131	1968	1	Yes	0	0	0
10	3131	1981	1	Yes	0	0	0
11	3131	1968	1	Yes	0	0	0
12	3131	1985	1	Yes	0	0	0

San Francisco (WBAN 23234)

Month	Radiosonde Station	Year	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	23230	1966	1	Yes	0	0	0
2	23230	1977	1	Yes	0	0	0
3	23230	1963	1	Yes	0	0	0
4	23230	1974	1	Yes	0	0	0
5	23230	1986	1	Yes	0	0	0
6	23230	1971	1	Yes	0	0	0
7	23230	1970	1	Yes	1	0	0
8	23230	1963	1	Yes	0	0	0
9	23230	1966	1	Yes	0	0	0
10	23230	1973	1	Yes	0	0	0
11	23230	1979	1	Yes	1	0	0
12	23230	1974	1	Yes	0	0	0

A.3.2 Month/Year Pairings for Empirical Stations

For the following stations, at least one month/year pairing was empirically determined. A "Yes" in the column "TMY2 Pair" indicates that the year listed matches the TMY2-selected year for that month; a "No" indicates that the month/year pairing was empirically determined. If the month/year pair was empirically determined, Column 4 (Candidate Months) reports the number of available candidate months from which the most typical was selected; otherwise, the value "N/A" appears. Columns 6-10 report the results of the data quality criteria and selection criteria. Those months for which the selected year used radiosonde data with a lower bound less than -2 or an upper bound greater than 3 (i.e., invalid months) are highlighted in **bold**.

Arcata_Medford (WBAN 24283)

Month	Year	TMY2 Pair	Candidate Months	Radiosonde Station	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	1968	Yes	N/A	24225	1	Yes	0	0	0
2	1973	Yes	N/A	24225	1	Yes	0	0	0
3	1975	Yes	N/A	24225	1	Yes	0	0	0
4	1974	Yes	N/A	24225	1	Yes	0	0	0
5	1980	Yes	N/A	24225	1	Yes	0	0	0
6	1984	No	43	24225	1	Yes	0	0	0
7	1982	No	43	24225	1	Yes	1	0	0
8	1975	No	43	24225	1	Yes	1	0	0
9	1972	Yes	N/A	24225	1	Yes	1	0	0
10	1980	Yes	N/A	24225	1	Yes	0	0	0
11	1971	Yes	N/A	24225	1	Yes	0	0	0
12	1979	Yes	N/A	24225	1	Yes	0	0	0

Arcata_Oakland (WBAN 24283)

Month	Year	TMY2 Pair	Candidate Months	Radiosonde Station	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	1968	Yes	N/A	23230	1	Yes	1	0	0
2	1963	No	42	23230	1	Yes	0	0	0
3	1975	Yes	N/A	23230	1	Yes	1	0	0
4	1967	No	43	23230	1	Yes	0	0	0
5	1961	No	43	23230	1	Yes	1	0	0
6	1978	No	43	23230	1	Yes	1	0	0
7	1989	Yes	N/A	23230	1	Yes	1	0	0
8	1971	No	41	23230	1	Yes	1	0	0
9	1974	No	42	23230	1	Yes	2	0	0
10	1981	No	42	23230	1	Yes	1	0	0
11	1963	No	43	23230	1	Yes	1	0	0
12	1966	No	41	23230	1	Yes	1	0	0

Bakersfield (WBAN 23155)

Month	Year	TMY2 Pair	Candidate Months	Radiosonde Station	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	1962	No	11	23203	1	Yes	1	0	0
2	1962	No	8	23203	1	Yes	0	0	0
3	1961	Yes	N/A	23203	1	Yes	0	0	3
4	**1955**	**No**	**3**	**23114**	**2**	**No**	**1**	**-3**	**4**
5	**1956**	**No**	**2**	**23203**	**1**	**No**	**1**	**0**	**3**
6	**1956**	**No**	**2**	**23203**	**1**	**No**	**0**	**0**	**4**
7	**1956**	**No**	**2**	**23203**	**1**	**No**	**0**	**0**	**4**
8	1956	No	2	23203	1	No	0	0	3
9	**1956**	**No**	**2**	**23203**	**1**	**No**	**0**	**0**	**5**
10	**1955**	**No**	**2**	**23203**	**1**	**No**	**0**	**0**	**4**
11	1961	No	9	23203	1	Yes	0	0	2
12	1961	No	8	23203	1	Yes	0	0	0

Fresno (WBAN 93193)

Month	Year	TMY2 Pair	Candidate Months	Radiosonde Station	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	1963	No	11	23203	1	Yes	0	-2	0
2	1962	No	8	23203	1	Yes	0	0	0
3	**1961**	**No**	**6**	**23203**	**1**	**Yes**	**0**	**0**	**3**
4	**1955**	**No**	**3**	**23114**	**2**	**No**	**1**	**-3**	**4**
5	**1957**	**No**	**2**	**23114**	**2**	**No**	**0**	**-3**	**0**
6	**1956**	**No**	**2**	**23203**	**1**	**No**	**2**	**0**	**4**
7	**1956**	**No**	**2**	**23203**	**1**	**No**	**0**	**0**	**4**
8	1956	No	2	23203	1	No	0	0	3
9	**1956**	**No**	**2**	**23203**	**1**	**No**	**0**	**0**	**5**
10	**1955**	**No**	**2**	**23203**	**1**	**No**	**0**	**0**	**4**
11	1961	No	9	23203	1	Yes	1	0	2
12	1961	No	8	23203	1	Yes	0	0	0

Santa Maria (WBAN 23273)

Month	Year	TMY2 Pair	Candidate Months	Radiosonde Station	Radiosonde Preference Group	SAMSON Reporting Period	Maximum Missing Span	Lower Bound	Upper Bound
1	1978	No	33	93214	1	Yes	0	0	0
2	1973	No	35	93214	1	Yes	0	0	0
3	1981	No	33	93214	1	Yes	1	0	0
4	1974	No	35	93214	1	Yes	0	-2	0
5	1968	No	35	93214	1	Yes	0	0	2
6	1963	Yes	N/A	93215	2	Yes	0	0	0
7	1979	Yes	N/A	93214	1	Yes	0	0	0
8	1979	Yes	N/A	93214	1	Yes	0	0	0
9	1965	Yes	N/A	93215	1	Yes	0	0	0
10	1975	No	30	93214	1	Yes	1	0	0
11	1966	No	32	93214	1	Yes	0	0	0
12	1974	Yes	N/A	93214	1	Yes	1	0	0

A.4 Meteorological Preprocessor Outputs

This section contains selected details about the output files of both meteorological preprocessors (mixhts.exe and PCRAMMET). File E (available from the authors upon request) contains annotated listings of all output files produced by both programs.

A.4.1 Filling of Twice-Daily Mixing Heights

Any gaps in twice-daily mixing heights were filled before input to PCRAMMET or, for those stations/months using the empirical CDF selection process, before construction of the monthly and long-term CDFs. Missing twice-daily mixing heights were linearly filled from the preceding and subsequent mixing heights from the same time period (AM or PM).

It should be noted that gaps were only filled for files with the potential to be used in constructing a TMHY year; that is, filling was performed only for candidate months selected by the empirical process. For most cases, only candidate months with a resultant maximum missing span of zero or one AM or PM mixing height were retained for use by the selection process; however, for a few stations, a candidate month with a maximum missing span of 2 was the best available candidate (i.e., Fresno, Arcata-Medford, and Sacramento).

By filling all gaps in the twice-daily mixing heights, PCRAMMET was able to produce 8760 hours of TMHY data for all stations without errors.

A.4.2 PCRAMMET Warning: Mixing Heights Less than 10 Meters

PCRAMMET provides warnings for all hours where urban or rural mixing heights are less than 10 m; the user of TMHYs should be aware that while the output files contain mixing heights less than 10 m, for the purposes of air dispersion modeling, these values should be reset to 10 m, which is standard procedure in regulatory air dispersion modeling (EPA, 2000).

A.4.3 PCRAMMET Modification of Wind Direction

Wind direction is provided in ten-degree bins in the SAMSON dataset. To compensate for bias introduced by the binning, PCRAMMET adds a random flow vector between -4 and 5 to the input wind direction, which produces wind directions in integer degrees (EPA, 1999). Therefore, the TMHY wind directions will not precisely match the input SAMSON files.

A.4.4 PCRAMMET Modification of Wind Speed

PCRAMMET converts wind speed taken from SAMSON files from m/s to knots, then back to m/s, to align with methods used for other data sources where wind speed is provided in knots (EPA, 1999). This unnecessary unit conversion introduces false precision in the wind speeds. Therefore, output values were replaced in the TMHYs with the original wind speeds provided in the SAMSON data set.

A.5 References

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A.6 Files available from the authors upon request

File A: TMY2-selected Month/Year Pairs
File B: Radiosonde Station Preference Groups
File C: Radiosonde Data Availability for Candidate Month/year Pairs for Surface Stations Using the Empirical Method in Development of the TMHY
File D: Station Identification and Map
File E: Supplementary Files

Appendix B. Plume Rise

Combustion products are typically emitted from stacks at elevated temperatures compared to the surrounding atmosphere and at substantial velocity. This causes the plume of emissions to rise compared to the physical height of the stack due to buoyancy and momentum effects, the former typically dominating. The height at which the plume is controlled by atmospheric conditions (stability and wind speed) as opposed to the conditions of its release is called the effective stack height. The effective stack height is used in Gaussian plume modeling to represent the height of the plume centerline, with a Gaussian concentration distribution for both increasing and decreasing *z*. The effective stack height (h) is equal to the sum of the physical stack height (h_s) and plume rise (Δh). Plume rise is affected by a number of parameters, including the conditions of release from the stack (exit velocity and difference between effluent temperature and ambient temperature), atmospheric stability, and wind speed. Multiple methods exist to determine the ultimate plume rise (Hanna et al., 1982, Seinfeld and Pandis, 1998, Turner, 1994, and ASME, 1979 all summarize the literature in slightly different ways, most of which are based on the work of Briggs (1969, 1971, 1974 and 1975)). We have chosen the method recommended by Turner (1994) because it is straightforward and only requires variables that are contained in either the meteorological or emission databases used in our study. The other sources supplement the Turner method in terms of assumptions and understanding.

Through different equations for unstable-neutral and stable conditions, one determines buoyancy and momentum-induced plume rise, taking the one producing the greater plume rise as dominant and equivalent to the final plume rise. The buoyancy flux parameter (F) is used under both atmospheric conditions and is given by

$$F = gvd^2\Delta T / 4T_s$$

where g is gravitational acceleration (9.8 m s^{-2}), v is the stack gas exit velocity (m s^{-1}), d is the inside diameter at the top of the stack (m), ΔT is the difference between the stack gas and ambient temperature (K), T_s is the stack gas temperature (K), providing F in units of m^4 s^{-3} (from eq. 12, p. 63 of Briggs, 1975).

B.1 Final Rise for Unstable-Neutral Conditions (Turner Stability Classes 1-4)

Calculate both buoyancy and momentum plume rise. The larger of the two is the final plume rise under unstable and neutral atmospheric conditions.

B.1.1 Buoyant Rise

For $F < 55$ m^4 s^{-3} (from eq. 6, p.103 of Briggs, 1971)

$$\Delta h = 21.425 F^{3/4} / u_h$$

where Δh is the height of the plume centerline above the source (m) and u_h is the wind speed at the top of the physical stack (m s^{-1}). (Note: for those stacks taller than 10 m, the wind speed will need to be adjusted using the wind speed at the reference height and the appropriate urban/rural power-law exponent.)

For $F > 55$ m^4 s^{-3} (from eq. 7, p. 103 of Briggs, 1971)

$$\Delta h = 38.71 F^{3/5} / u_h$$

These equations are based on curve fits to empirical data.

B.1.2 Momentum Rise

$$\Delta h = 3\ dv / u_h$$

(from eq. 5.2, p. 59, of Briggs, 1969).

B.2 Final Rise for Stable Conditions (Turner Stability Classes 5-7)

B.2.1 Buoyant Rise

For this calculation, an intermediate variable, the stability parameter, must be calculated (from p.1031 of Briggs, 1971):

$$s = \left(g\, d\theta / dz \right) / T$$

where $d\theta/dz$ is the change in potential temperature with height (K/m) and T is the ambient temperature (K). Note, $d\theta/dz = dT/dz + \Gamma$, where Γ is the adiabatic lapse rate (0.0098 K/m). The American Society of Mechanical Engineers (ASME) provides a point estimate for the potential temperature gradient where using actual measurements is not practical (ASME, 1979): for stability class E (5), $d\theta/dz = 0.02$ K/m and for class F (6), $d\theta/dz = 0.04$ K/m.

Final rise is then

$$\Delta h = 2.6\left[F/(u_h s)\right]^{1/3}$$

(from eq. 50, p.96 in Briggs, 1975).

B.2.2 Momentum Rise

The lesser of the unstable-neutral momentum rise and the result of the equation below is deemed the final momentum rise. The final momentum rise is then compared to that for stable buoyant rise. The final stable plume rise is the larger of the momentum rise and the buoyant rise.

$$\Delta h = 1.5\left[\left(v^2 d^2 T\right)/\left(4T_s u_h\right)\right]^{1/3} s^{-1/6}$$

(from eq 4.28, p. 59 in Briggs, 1969).

B.3 References

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